Air Quality

6.2 AIR QUALITY

This section describes existing air quality conditions, maximum potential impacts from the Project, and mitigation measures that keep these impacts below thresholds of significance. The Project will use combined-cycle generation technology to replace existing Units 1, 2, 3, and 4, minimizing the amount of fuel needed to produce electricity, emissions of criteria pollutants, and potential effects on ambient air quality.

Other beneficial environmental aspects of the Project that minimize adverse air quality include the following:

- Clean-burning natural gas as fuel.
- Selective catalytic reduction (SCR) to minimize NOx emissions.
- Oxidation catalysts to reduce carbon monoxide emissions.
- Appropriately sized stacks to reduce ground-level concentrations of exhaust constituents.

This section presents the methodology and results of the air quality analyses performed to assess potential impacts associated with air emissions from the construction of the Project. Potential public health risks posed by emissions of noncriteria pollutants are also addressed in Section 6.16 (Public Health).

Section 6.2.1 provides a summary of this air quality section. Existing air quality conditions are described in Sections 6.2.2 through 6.2.4. Applicable regulations are discussed in Section 6.2.5. The methodology used in the quantitative air quality analysis and the resulting potential impacts are presented in Section 6.2.6. Consistency with laws, ordinances, regulations, and standards (LORS) is discussed in Section 6.2.7. The protocol for analyzing cumulative air quality impacts is presented in Section 6.2.8. Measures that mitigate the potential impacts to air quality are discussed in Section 6.2.9. References cited in this chapter are listed in Section 6.2.10.

6.2.1 SUMMARY OF AIR QUALITY IMPACTS

Duke is proposing to replace the four existing boilers at MBPP with four new combined-cycle turbines. Combined-cycle turbine technology is a more efficient way to generate electricity, requiring less fuel than the old boilers to generate the same amount of power. These new combined-cycle turbines produce very low levels of air pollutant emissions, and their emissions of oxides of nitrogen will be controlled to even lower levels using selective catalytic reduction (SCR) technology.

Before the new turbines can be built, Duke needs to receive regulatory approval from three agencies that will review the air quality impacts of the proposed project: the San Luis Obispo County Air Pollution Control District (SLOCAPCD or District), the Environmental Protection Agency (EPA), and the California Energy Commission. Each agency has its own set of standards for review, but the goals of the agencies are the same:

- to ensure that the operation of the new turbines will not cause or contribute to the violation of any health-based ambient air quality standards; and
- to ensure that the emissions of potentially toxic pollutants from the turbines will not cause any health hazards.

Each agency's review asks several questions about the project. The questions are as follows:

- What is the existing air quality in the area?
- How much will the new turbines operate?
- What are the air pollutant emissions from the new project?
- How do these compare with the emissions from the existing power plant?
- Is the new project using the best control technology available to control its emissions?
- How will the new project mitigate any increase in emissions over existing levels?
- Once the project is in operation, what will be the effect on air quality in the area?
- Will the new project emit toxic pollutants in quantities that could be harmful to the health of the most sensitive members of the community?

The air quality section of the AFC answers these questions in detail. The purpose of this summary is to provide an outline of the information in the AFC that answers these questions. The summary refers the reader to specific sections of the AFC to find more information about each topic. Finally, the sections of the AFC often refer the reader to appendices that contain the detailed calculations that support each conclusion.

6.2-1.1 What is the existing air quality in the area?

EPA has established national ambient air quality standards (NAAQS) for ozone, nitrogen dioxide (NO_2), carbon monoxide (CO), sulfur dioxide (SO_2), and fine particulate matter (PM_{10}). Areas with air pollution levels above these standards can be considered "nonattainment areas" subject to planning and pollution control requirements that are more stringent than standard requirements.

In addition, the California Air Resources Board (ARB) has established standards for ozone, CO, NO_2, SO_2, sulfates, PM_{10}, airborne lead, hydrogen sulfide, and vinyl chloride at levels designed to protect the most sensitive members of the population, particularly children, the elderly, and people who suffer from lung or heart diseases.

Both state and national air quality standards consist of two parts: an allowable concentration of a pollutant, and an averaging time over which the concentration is to be measured. Allowable concentrations are based on the results of studies of the effects of the pollutants on human health, crops and vegetation, and, in some cases, damage to paint and other materials. The averaging times are based on whether the damage caused by the pollutant is more likely to occur during exposures to a high concentration for a short time (one hour, for instance) or to a relatively lower average concentration over a longer period (8 hours, 24 hours, or 1 month). For some pollutants there is more than one air quality standard, reflecting both their short-term and long-term effects. The California standards are generally set at concentrations much lower than the federal standards and in some cases have shorter averaging periods. Air quality in the District is in attainment with most of the federal and state standards, with the exception of the federal ozone standard and the state 24-hour PM_{10} standard. While ozone levels in Morro Bay are in compliance with the federal standard, levels measured elsewhere in the District are above the standards and as a result the District is considered "nonattainment" for ozone. The state 24-hour PM_{10} standard is significantly lower than the federal standard (50 ug/m^3 vs. 150 ug/m^3), and most areas of the state exceed the state standard but are below the federal standard.

Three ambient air monitoring stations were used to characterize air quality at the Project site. These stations were used because of their proximity to the Project site and because they record area-wide ambient conditions rather than the localized impacts of any particular facility. Ambient concentrations of ozone and fine particulate matter (PM_{10}) are recorded at a monitoring station in Morro Bay. Carbon monoxide (CO) and nitrogen dioxide (NO_2) are monitored in San Luis Obispo. Sulfur dioxide (SO_2) is monitored at Grover City. Table 6.2-1 summarizes the ambient concentrations of air pollutants measured in or near Morro Bay between 1997 and 1999 and compares them with the federal and state ambient air quality standards.

TABLE 6.2-1
MAXIMUM BACKGROUND CONCENTRATIONS, 1997-1999 ($\mu g/m^3$)

POLLUTANT	AVG TIME	Maximum Monitored Concentration			Air Quality Standard	
		1997	1998	1999	State	Federal
Ozone[1]	1 hour	0.06	0.07	0.10	0.09	0.12
NO_2	1-Hour Annual	122 25	115 23	120 25	470 n/a	n/a 100
CO	1-Hour 8-Hour	6,988 3,028	4,571 2,555	5,714 3,444	23,000 10,000	40,000 10,000
SO_2	1-Hour 24-hour Annual	106 8 0	47 10 0	104 13 0	655 105 n/a	n/a 365 80
PM_{10}	24-Hour AAM[2] AGM[3]	57 20.6 18.6	33 13.5 14.6	39 14.4 15.7	50 n/a 30	150 50 n/a

Notes:
1. Ozone concentration expressed in parts per million.
2. Annual arithmetic mean.
3. Annual geometric mean.

6.2.1.2 How much will the new turbines operate?

Duke expects that each new turbine will operate up to 8,400 hours per year, out of a possible 8,760 hours. Because these turbines will run only when there is a demand for electricity, each turbine may be shut down at night and started up in the morning. Thus Duke is planning that during up to 400 of those 8,400 hours, each turbine may be starting up or shutting down.

Each turbine and heat recovery steam generator (HRSG) is equipped with duct burners that add heat to the steam generator. This allows each steam generator to generate more steam for the steam turbine, so that when demand for electricity is high, each turbine/HRSG can produce more electricity. Duke plans that the duct burners may operate up to 16 hours each day and up to 4,000 hours each year.

6.2.1.3 What are the air pollutant emissions from the new project, and how do they compare with the emissions from the existing power plant?

Air pollutant emissions from the new turbines are calculated using proposed emissions limits during each of the operating modes described above: startup/shutdown, base load (without duct burning), and with duct burning. The proposed emissions limits will become permit conditions, as will the limits on hours of operation in the various modes. Emissions, fuel use, and generation will be monitored continuously for each turbine to ensure that the turbines/HRSGs are always in compliance with their permit limits. Table 6.2-2 shows the highest allowable hourly, daily, and annual emissions from the four new turbines/HRSGs. Detailed calculations are shown in Section 6.2.6.2.2 of the AFC.

TABLE 6.2-2
EMISSIONS FROM NEW TURBINES

	NOx	SO_2	CO	VOC	PM_{10}
Maximum Hourly Emissions, lb/hr	198.6	5.8	1,296.5	42.8	53.2
Maximum Daily Emissions, lb/day	2,784.0	134.4	12,119.2	644.3	1,203.2
Maximum Annual Emissions, tpy	292.3	23.0	917.4	77.6	203.2

Emissions from the existing boilers are characterized by the average emissions over the past two years (August 1998 through July 2000)*. The boilers have emissions monitors that continuously measure NOx and CO emissions, forming the basis for the NOx and CO emissions shown below for the boilers. The SO_2 emissions are calculated from the very small quantity of sulfur in the fuel. The VOC and PM_{10} emissions are calculated using standard EPA emission factors. Table 6.2-3 shows the emissions from the existing boilers. Detailed calculations are shown in Section 6.2.6.2.1 of the AFC.

TABLE 6.2-3
EMISSIONS REDUCTIONS FROM EXISTING BOILERS

	EMISSIONS, tons per year				
	NOx	SO_2	CO	VOC	PM_{10}
Unit 1	193.3	1.1	80.0	10.3	14.2
Unit 2	273.5	1.3	24.8	12.2	16.8
Unit 3	170.9	3.7	644.7	33.9	46.9
Unit 4	217.7	3.9	686.5	35.7	49.3
Total	855.4	10.0	1,436.0	92.1	127.2

Table 6.2-4 compares the emissions from the new turbines with the emissions from the existing boilers.

* Different baseline periods are required for different regulatory programs, as discussed further below. The two-year baseline presented here is used for purposes of CEQA and federal programs.

TABLE6.2-4
COMPARISON OF EMISSIONS FROM NEW TURBINES AND EXISTING BOILERS

	EMISSIONS (tons per year)						
	NOx	SO_2	CO	VOC	PM_{10}	Total O_3 Precursors	Total PM_{10} Precursors
New Turbines	292.3	23.0	917.4	77.6	203.2	369.9	596.1
Existing Boilers	855.4	10.0	1,436.0	92.1	127.2	947.5	1,084.7
Difference	(-563.1)	13.0	(-518.6)	(-14.5)	76.0	(-577.6)	(-488.6)

6.2.1.4 Is the new project using the best control technology available to control its emissions?

The project is required to use best available control technology to control its emissions. The applicant has reviewed permit requirements approved by the EPA, the state Air Resources Board, and the CEC staff and believes that the following emissions limits reflect the best available controls:

NOx: 2.5 parts per million by volume, dry (ppmvd), corrected to 15% O_2
SO_2: Use of natural gas fuel with a sulfur content not to exceed 0.25 grains per 100 standard cubic feet
CO: 6 ppmvd, corrected to 15% O_2
VOC: 2 ppmvd, corrected to 15% O_2
PM_{10}: 11 pounds per hour without duct firing; 13.3 pounds per hour with duct firing

A detailed discussion of control technology options can be found in Section 6.2.7.3 of the AFC.

6.2.1.5 How will the new project offset any increase in emissions over existing levels?

Duke is required to provide offsets for any increase in emissions that will result from the operation of the new turbines. Many of the emissions offsets will come from the shutdown of the existing boilers.* The District has also granted Duke ERCs in exchange for eliminating fuel oil use in the existing boilers, and Duke will use these ERCs to offset a portion of the increase as well. Finally, as discussed further below, Duke has purchased ERCs from Chevron that will be used to offset the remainder of the emissions increase from the project.

* The District discounts emissions reductions from shutdowns by 20% or more before granting emission reduction credits, or ERCs. Therefore, Duke will receive only 8 or fewer tons of credit for every 10 tons of emissions eliminated by shutting down the existing boilers.

District regulations allow the use of interpollutant offsets in situations where one pollutant is a precursor to another. For example, since both NOx and VOC emissions are precursors of ozone, Duke will use extra VOC ERCs to offset some of its NOx emissions increases. Similarly, since SO_2 contributes to the formation of PM_{10}, Duke will use extra SO_2 ERCs to offset some of its PM_{10} increases. Offsets are discussed in detail in Section 6.2.7.3.2 of the AFC.

6.2.1.6 Once the project is in operation, what will be the effect on air quality in the area?

Federal and District regulations and CEC requirements necessitate an analysis of the impact of the project on ambient air quality to ensure that the project will not cause or contribute to the violation of any state or federal ambient air quality standards and increments. Air quality impacts are evaluated using EPA-approved computer models that use worst-case emission rates, exhaust stack parameters (including stack heights and exhaust flow rates), and local meteorology to simulate the dispersion of emissions and to determine the maximum ground-level impacts. These models account for the effects of nearby buildings and local terrain. As requested by the SLOCAPCD, Duke has used three years of weather data (wind speed, wind direction and temperature) measured at the plant, and inversion heights measured at Vandenberg AFB, to ensure that impacts are evaluated under the most extreme conditions.

The dispersion of emissions from existing boilers and the new turbines were modeled to determine their impacts on ambient air quality. For the turbines, Duke also looked at modeled impacts during startup when emission rates may be high for short periods of time, during times in the early morning when mixing heights are very low (potentially causing inversion breakup fumigation), and during periods when a temperature difference between land and water cause the exhaust plumes to loop down before much dispersion of the pollutants has occurred (shoreline fumigation). EPA-approved models are designed to be conservative, so the modeling results typically overestimate the actual concentrations that would be measured.

Maximum modeled impacts from both the boilers and the turbines were found to occur on Morro Rock. When the receptors on the Rock are excluded, modeled impacts from the turbines are found to be much lower. Modeling results are summarized in Table 6.2-6.

TABLE 6.2-5
SUMMARY OF MODELING RESULTS[1]

POLLUTANT	AVERAGING TIME	MODELED CONCENTRATIONS ($\mu g/m^3$)			
		ISCST3	FUMIGATION	SHORELINE FUMIGATION	STARTUP
NO_x[2]	1-hour	220.4	13.3	105.1	185.9
	Annual	2.6	--	--	--
SO_2	1-hour	17.3	1.03	8.1	11.9
	3-hour	11.9	0.93	4.1	8.3
	24-hour	2.7	0.41	0.54	--
	Annual	0.23	--	--	--
CO	1-hour	326.3	19.5	153.6	8,615.4
	8-hour	1,508.3	159.3	347.7	--
PM_{10}	24-hour	24.2	3.6	4.6	--
	Annual	2.7	--	--	--

(1) New combined cycle units only.
(2) Modeled using ISC_OLM with concurrent ozone data to account for ozone limiting of NO_2 formation.

The highest modeled turbine impacts under any of these conditions were added to the highest background concentration measured at nearby air quality monitoring stations during the past three years to demonstrate that the combination of the new project with existing background pollutant concentrations will not cause any standards to be exceeded. This comparison is shown in Table 6.2-6. To be conservative, this analysis does not take into account the improvement in air quality that will result from shutting down the existing boilers.

TABLE 6.2-6
MODELED MAXIMUM PROJECT IMPACTS

POLLUTANT	AVERAGING TIME	MAXIMUM PROJECT IMPACT (1) ($\mu g/m^3$)	BACKGROUND CONCEN-TRATIONS ($\mu g/m^3$)	TOTAL IMPACT ($\mu g/m^3$)	STATE STANDARD ($\mu g/m^3$)	FEDERAL STANDARD ($\mu g/m^3$)
NO_2	1-hour	220.4	122		470	--
	Annual	2.6	25	27.6	--	100
SO_2	1-hour	17.3	106	123.3	650	--
	24-hour	2.7	13	15.7	109	365
	Annual	0.23	0	0.23	--	80
CO	1-hour	8,615.4	6,988	15,603.4	23,000	40,000
	8-hour	1,508.3	3,444	4,952.3	10,000	10,000
PM_{10}	24-hour	24.2	57	81.2	50	150
	Annual(2)	2.7	20.6	23.3	30	--
	Annual(3)	2.7	18.6	21.3	--	50

(1) New combined cycle units only
(2) Annual geometric mean
(3) Annual arithmetic mean

The ambient air quality analysis and the data used to represent background concentrations are discussed in detail in Section 6.2.6.3 of the AFC.

6.2.1.7 Will the new project emit toxic pollutants in quantities that could be harmful to the health of the most sensitive members of the community?

SLOCAPCD Rule 219, Toxics New Source Review, and CEC licensing procedures require an assessment of the potential impacts of the project on public health and a demonstration that the emissions of potentially toxic substances from the project will not pose a health hazard to the most sensitive members of the community. This demonstration was made using a screening health risk assessment. In a screening health risk assessment, the short-term (acute), long-term (chronic), and carcinogenic impacts of exposures to potentially toxic substances are compared with generally accepted risk criteria to show that the project is safe. The screening health risk assessment is carried out in three steps:

- Estimate emissions of toxic, or noncriteria pollutants, from each source;
- Use dispersion modeling to calculate the ground-level concentration of each pollutant; and
- Use scientifically derived cancer unit risk factors and acute and chronic reference exposure levels (levels below which no harmful effects are observed) to evaluate carcinogenic risk and chronic and acute noncancer health hazards.

A screening health risk assessment was performed for both the existing plant (the existing boilers plus the Diesel-fueled fire pumps and emergency generator, and gasoline dispensing facility) and the new project (new turbines plus the existing support equipment). Toxic emissions were calculated using ARB-approved emission factors and emissions measurements. The dispersion modeling used the same EPA-approved models and meteorological data that were used in modeling criteria pollutant impacts.

The results of the screening health risk assessment for the new turbines are compared with the limits of District Rule 219 in Table 6.2-7 below; the results are well below all significance levels.

TABLE 6.2-7
HEALTH RISK ASSESSMENT RESULTS

	Turbines	Significance Threshold
Cancer Risk to Maximally Exposed Individual	0.1 in one million	1 in one million
Acute Noncancer Hazard Index	0.08	0.1
Chronic Noncancer Hazard Index	0.001	0.1

The screening health risk assessment is discussed in detail in Sections 6.2.6.4 and 6.16 (Public Health) of the AFC.

6.2.2 EXISTING CONDITIONS

6.2.2.1 Geography and Topography

The Project is located on the site of the existing Morro Bay Power Plant (MBPP) in the city of Morro Bay, between State Highway 1 and the Pacific Ocean. The Project site is level, at an elevation of approximately 20 feet above sea level, approximately 0.2 miles from the Pacific Ocean. The nearest residences are approximately one-quarter mile southeast. Immediately west of the Project site and extending north approximately two miles is the Morro Strand State Beach. To the south of the site lie Morro Bay, Morro Bay State Park, the Montaña De Oro State Park, and Morro Dunes Natural Preserve. The towns of Baywood Park, Los Osos, and Cuesta-by-the-Sea lie approximately four miles to the south. To the southeast of the Project site is the city of Morro Bay. Northeast of the Project is the valley of Morro Creek. Due east of the site the hills of the Coast Range rise to heights of 500 to 600 feet within one mile. Approximately 0.6 mile west-southwest of the site lies Morro Rock, elevation 578 feet.

6.2.2.2 Climate and Meteorology

The overall climate at the Project site is dominated by the semi-permanent eastern Pacific high pressure system centered off the coast of California. This high is centered between the 140° west (W) and 150° W meridians, and oscillates in a north-south direction. Its position governs California's weather. In the summer, the high moves to its northernmost position, which results in a strong subsidence inversion and clear skies inland; along the coast, the weather is dominated by coastal stratus and fog caused by the cooler and more homogeneous ocean surface temperature. Often in the summer, fog comes onshore during late afternoon and persists until the middle of the following morning.

In the winter, the high moves southwestward toward Hawaii, which allows storms originating in the Gulf of Alaska to reach northern California, bringing wind and rain. About 80 percent of the region's annual rainfall (10 to 30 inches, depending on altitude and proximity to the ocean) occurs between November and March.[1] Average precipitation at the Project site is about 16 inches per year. Between storms, skies are fair, winds are light, and temperatures are moderate.

Temperature, wind speed, and direction data have been recorded at a meteorological monitoring station at the Project site, operated by the Pacific Gas and Electric Company (PG&E) at MBPP. Temperatures at the site are moderated by the proximity to the ocean. In summer, daily temperatures at Morro Bay range from the low 50s to the mid-70s (degrees Fahrenheit [°F]). In winter, average lows are about 42° F, and average highs are about 60° F.[2]

Air quality is determined primarily by the type and amount of pollutants emitted into the atmosphere, the topography of the air basin, and local meteorological conditions. In the Project area, stable atmospheric conditions and light winds can provide conditions for pollutants to accumulate in the air basin when emissions are produced. The predominant winds in California are shown in Figures 6.2-1 through 6.2-4. As indicated in the figures, winds in California generally are light and easterly in the winter, but strong and westerly in the spring, summer, and fall.

Wind patterns at the Project site can be seen in Figures 6.2-5a through 6.2-7e, which show quarterly and annual wind roses for meteorological data collected at the PG&E Morro Bay weather station during 1994, 1995 and 1996. It can be seen that the winds are persistent (only 14 percent calm conditions) and predominantly from the western quadrant. On an annual basis, approximately 18 percent of the winds come from west-northwest, and a total of about 44 percent from southwest through northwest. Winds are predominantly from the northeast during the winter months.

The marine climate influences mixing heights. Often, the base of the inversion is found at the top of a layer of marine air, because of the cooler nature of the marine environment. Inland areas, where the marine influence is absent, often experience strong ground-based inversions, which inhibit mixing and can result in high pollutant concentrations. Smith, et al, (1984) reported that at Vandenburg Air Force Base, the nearest upper-level meteorological station (located approximately 45 miles SE of the Project site), 50th percentile morning mixing heights for the period 1979–80 were on the order of 900-1300 feet (270-395 meters) in summer and fall,

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1 "Climate of the States—California," U.S. Department of Commerce, Weather Bureau, December 1959.
2 Ibid.

and 1,700–3,500 feet (530-1,055 meters) in winter and spring. The 50th percentile afternoon mixing heights ranged from 1350 and 1450 feet (415–445 meters) in summer and fall, and from 3250 to over 3900 feet (990 to >1200 meters) in winter and spring. Such mixing heights provide generally favorable conditions for the dispersion of pollutants.

6.2.3 OVERVIEW OF AIR QUALITY STANDARDS

The U.S. Environmental Protection Agency (EPA) has established national ambient air quality standards (NAAQS) for ozone, nitrogen dioxide (NO_2), carbon monoxide (CO), sulfur dioxide (SO_2), particulate matter with aerodynamic diameter less than or equal to 10 microns (PM_{10}), particulate matter with aerodynamic diameter less than or equal to 2.5 microns ($PM_{2.5}$), and airborne lead. Areas with air pollution levels above these standards can be considered "nonattainment areas" subject to planning and pollution control requirements that are more stringent than standard requirements.

In addition, the California Air Resources Board (ARB) has established standards for ozone, CO, NO_2, SO_2, sulfates, PM_{10}, airborne lead, hydrogen sulfide, and vinyl chloride at levels designed to protect the most sensitive members of the population, particularly children, the elderly, and people who suffer from lung or heart diseases.

Both state and national air quality standards consist of two parts: an allowable concentration of a pollutant, and an averaging time over which the concentration is to be measured. Allowable concentrations are based on the results of studies of the effects of the pollutants on human health, crops and vegetation, and, in some cases, damage to paint and other materials. The averaging times are based on whether the damage caused by the pollutant is more likely to occur during exposures to a high concentration for a short time (one hour, for instance), or to a relatively lower average concentration over a longer period (8 hours, 24 hours, or 1 month). For some pollutants there is more than one air quality standard, reflecting both short-term and long-term effects. Table 6.2-8 presents the NAAQS and California ambient air quality standards for selected pollutants. The California standards are generally set at concentrations much lower than the federal standards and in some cases have shorter averaging periods.

EPA's new NAAQS for ozone and fine particulate matter went into effect on September 16, 1997. For ozone, the previous one-hour standard of 0.12 ppm was replaced by an eight-hour average standard at a level of 0.08 ppm. Compliance with this standard will be based on the three-year average of the annual 4th-highest daily maximum eight-hour average concentration measured at each monitor within an area.

The NAAQS for particulates were revised in several respects. First, compliance with the current 24-hour PM_{10} standard will now be based on the 99th percentile of 24-hour concentrations at each monitor within an area. Two new $PM_{2.5}$ standards were added: a standard of 15 $\mu g/m^3$, based on the three-year average of annual arithmetic means from single or multiple monitors (as available); and a standard of 65 $\mu g/m^3$, based on the three-year average of the 98th percentile of 24-hour average concentrations at each monitor within an area.

Recent court decisions have delayed the implementation of these new standards.

TABLE 6.2-8
AMBIENT AIR QUALITY STANDARDS

POLLUTANT	AVERAGING TIME	CALIFORNIA	NATIONAL
Ozone	1 hour	0.09 ppm	0.12 ppm
	8 hours	-	0.08 ppm (3-year average of annual 4th-highest daily maximum)
Carbon Monoxide	8 hours	9.0 ppm	9 ppm
	1 hour	20 ppm	35 ppm
Nitrogen Dioxide	Annual Average	-	0.053 ppm
	1 hour	0.25 ppm	-
Sulfur Dioxide	Annual Average	-	80 μg/m^3 (0.03 ppm)
	24 hours	0.04 ppm (105 μg/m^3)	365 μg/m^3 (0.14 ppm)
	3 hours	-	1300[1] μg/m^3 (0.5 ppm)
	1 hour	0.25 ppm	-
Suspended Particulate Matter (10 Micron)	Annual Geometric Mean	30 μg/m^3	-
	24 hours	50 μg/m^3	150 μg/m^3
	Annual Arithmetic Mean	-	50 μg/m^3
Suspended Particulate Matter (2.5 Micron)	Annual Arithmetic Mean	-	15 μg/m^3 (3-year average)
	24 hours	-	65 μg/m^3 (3-year average of 98th percentiles)
Sulfates	24 hours	25 μg/m^3	-
Lead	30 days	1.5 μg/m^3	-
	Calendar Quarter	-	1.5 μg/m^3
Hydrogen Sulfide	1-hour	0.03 ppm	-
Vinyl Chloride	24-hour	0.010 ppm	-
Visibility Reducing Particles	8-hour (10am to 6pm PST)	In sufficient amount to produce an extinction coefficient of 0.23 per kilometer due to particles when the relative humidity is less than 70 percent.	-

(1) This is a national secondary standard, which is designed to protect public welfare.

6.2.4 AIR QUALITY TRENDS (CRITERIA POLLUTANTS)

Three ambient air monitoring stations were used to characterize air quality at the Project site. These stations were used because of their proximity to the Project site and because they record area-wide ambient conditions rather than the localized impacts of any particular facility.* All ambient air quality data presented in this section were taken from ARB publications and data sources. Ambient concentrations of ozone and fine particulate matter (PM_{10}) are recorded at a monitoring station in Morro Bay operated by the San Luis Obispo County APCD. Carbon monoxide (CO) and nitrogen dioxide (NO_2) are monitored in San Luis Obispo at a station operated by the ARB. Sulfur dioxide (SO_2) is monitored at Grover City at a station operated by the San Luis Obispo County APCD. SO_2 was also monitored at Morro Bay through 1995 at a station operated by the San Luis Obispo County APCD. Ambient SO_2 data from both monitoring sites are presented in this discussion. Particulate sulfates and airborne lead have not been monitored anywhere in San Luis Obispo County since before 1988.

6.2.4.1 Ozone

Ozone is generated by complex reactions between reactive organic gases (ROG) and oxides of nitrogen (NOx) in the presence of ultraviolet radiation. ROG and NOx emissions from vehicles and stationary sources, in combination with daytime wind flow patterns, mountain barriers, a persistent temperature inversion, and intense sunlight, result in high ozone concentrations. San Luis Obispo County is in attainment of the federal ozone standard, but is designated a nonattainment area for the more stringent state standard, due to violations that occur at various locations throughout the county.

Maximum ozone concentrations at the Morro Bay station are usually recorded during the summer months. Table 6.2-9 shows the annual maximum hourly ozone levels recorded at the Morro Bay station during the period from 1990–1999, as well as the number of days in which the state and federal standards were exceeded. The data show that the state ozone air quality standard has been exceeded on only one day in 1991, 1992 and 1999. The federal standard was not exceeded during the 10-year period.

* A more extensive discussion of why the data from these stations are considered to be representative of air quality in the vicinity of the proposed project is provided in Section 6.2.6.3.3.

TABLE 6.2-9
OZONE LEVELS AT MORRO BAY
1990-1999
(parts per million - ppm)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Highest 1-Hour Average	.09	.10	.10	.08	.06	.07	.07	.06	.07	.10
Number of Days Exceeding:										
State Standard (0.09 ppm, 1-hour)	0	1	1	0	0	0	0	0	0	1
Federal Standard (0.12 ppm, 1-hour)	0	0	0	0	0	0	0	0	0	0

Source: California Air Quality Data, Annual Summary, California Air Resources Board

The long-term trends of maximum one-hour ozone readings and violations of the state standard are shown in Figures 6.2-8a and 6.2-8b, respectively, for Morro Bay. These charts illustrate that violations of the ozone standards are rare.

6.2.4.2 Nitrogen Dioxide

Nitrogen dioxide is formed primarily from reactions in the atmosphere between nitric oxide (NO) and oxygen or ozone. Nitric oxide is formed during high temperature combustion processes, when the nitrogen and oxygen in the combustion air combine. Although NO is much less harmful than NO_2, it is converted to NO_2 in the atmosphere within a matter of hours, or even minutes under certain conditions. For purposes of state and federal air quality planning, San Luis Obispo County is in attainment for NO_2.

Table 6.2-10 shows the annual maximum one-hour NO_2 levels recorded at the San Luis Obispo monitoring station each year from 1990 through 1999, as well as the annual average level for each of those years. During this period, there have been no violations of either the state one-hour standard (0.25 ppm) or the federal annual average standard (0.053 ppm). Figure 6.2-9 shows the trend from 1990 through 1999 of maximum one-hour NO_2 levels at San Luis Obispo. These have been well below the state standard of 0.25 ppm for many years.

TABLE 6.2-10
NITROGEN DIOXIDE LEVELS AT SAN LUIS OBISPO
1990-1999
(parts per million - ppm)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Highest 1-Hour Average	.07	.07	.06	.07	.07	.07	.06	.07	.06	.06
Annual Average	.014	.014	.013	.014	.015	.013	.013	.013	.012	.013
Number of Exceedances:										
State Standard (Days) (0.25 ppm, 1-hour)	0	0	0	0	0	0	0	0	0	0
Federal Standard (Years) (0.052 ppm, annual)	0	0	0	0	0	0	0	0	0	0

Source: California Air Quality Data, Annual Summary, California Air Resources Board

6.2.4.3 Carbon Monoxide

Carbon monoxide is a product of inefficient combustion, principally from automobiles and other mobile sources of pollution. In many areas of California, CO emissions from wood-burning stoves and fireplaces can also be measurable contributors. Industrial sources typically contribute less than 10% of ambient CO levels. Peak CO levels occur typically during winter months, due to a combination of higher emission rates and stagnant weather conditions. For purposes of state and federal air quality planning, San Luis Obispo County is classified as being in attainment for CO.

Table 6.2-11 shows the California and federal air quality standards for CO, and the maximum one-hour and eight-hour average levels recorded at the San Luis Obispo monitoring station during the period from 1990–1999.

Trends of maximum eight-hour and one-hour average CO are shown in Figures 6.2-10 and 6.2-11, respectively, which show that maximum ambient CO levels at San Luis Obispo have been below the state standards for many years, and continue to decline.

TABLE 6.2-11
CARBON MONOXIDE LEVELS AT SAN LUIS OBISPO
1990-1999
(parts per million - ppm)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Highest 8-hour average	4.1	3.3	3.1	3.2	3.4	3.1	2.9	2.6	2.3	3.1
Highest 1-hour average	10	8	8	9	6	6	5	6	4	5
Number of days exceeding:										
State Standard (20 ppm, 1-hr)	0	0	0	0	0	0	0	0	0	0
State Standard (9.0 ppm, 8-hr)	0	0	0	0	0	0	0	0	0	0
Federal Standard (35 ppm, 1-hr)	0	0	0	0	0	0	0	0	0	0
Federal Standard (9 ppm, 8-hr)	0	0	0	0	0	0	0	0	0	0

Source: California Air Quality Data, Annual Summary, California Air Resources Board

6.2.4.4 Sulfur Dioxide

Sulfur dioxide is produced when any sulfur-containing fuel is burned. It is also emitted by chemical plants that treat or refine sulfur or sulfur-containing chemicals. Natural gas contains a negligible amount of sulfur, while fuel oils contain much larger amounts. Because of the complexity of the chemical reactions that convert SO_2 to other compounds (such as sulfates), peak concentrations of SO_2 occur at different times of the year in different parts of California, depending on local fuel characteristics, weather, and topography. San Luis Obispo County is considered to be in attainment for SO_2 for purposes of state and federal air quality planning.

Table 6.2-12 presents the state air quality standard for SO_2 and the maximum levels recorded in Grover City from 1988 through 1997 and from Morro Bay from 1988 through 1995 (after which monitoring ceased). Maximum one-hour average readings have been an order of magnitude below the state standard. The federal annual average standard is 0.03 ppm; during most of the period shown, annual average SO_2 levels at these two sites have been less than one-tenth of the federal standard. Figure 6.2-12 shows that for several years the maximum SO_2 levels at both sites generally have been less than one fifth of the state standard.

TABLE 6.2-12
SULFUR DIOXIDE LEVELS IN SAN LUIS OBISPO COUNTY
MORRO BAY AND GROVER CITY
1988–1997
(parts per million/ppm)

		1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
Highest 1-Hour Average	Morro Bay	.05	.02	.02	.01	.01	.01	.01	.02	--	--
	Grover City	.03	.03	.08	.03	.03	.04	.04	.03	.03	.04
Annual Average	Morro Bay	.013	.000	.000	.000	.000	.000	.000	.000	--	--
	Grover City	.006	.001	.001	.000	.000	.000	.000	.000	.000	.001
Number of Exceedances:											
State Standard (Days) (0.25 ppm, 1-hr)		0	0	0	0	0	0	0	0	0	0
Federal Standard (Years) (0.03 ppm, annual)		0	0	0	0	0	0	0	0	0	0

Source: California Air Quality Data, Annual Summary, California Air Resources Board

6.2.4.5 Particulate Sulfates

Particulate sulfates are the product of further oxidation of SO_2. Elevated levels can also result from natural causes, such as sea spray. San Luis Obispo County is in attainment with the state standard for sulfates. There is no federal standard for sulfates.

Due to the extremely low levels found, sulfates have not been monitored in San Luis Obispo County since 1987 and have not been monitored anywhere in either the North Central Coast or the South Central Coast air basin since 1990. Table 6.2-13 presents maximum 24-hour average sulfate levels recorded at Santa Maria, in Santa Barbara County, the monitoring station closest to the Project site, for the period of 1988–1990. During the period when sulfates were monitored at both San Luis Obispo and Santa Maria, the levels at Santa Maria were typically 1½ to 2 times higher than those at San Luis Obispo. Therefore, the levels shown in Table 6.2-13, while well below the state standard, still provide a conservatively high estimate of actual sulfate levels at Morro Bay.

TABLE 6.2-13
PARTICULATE SULFATE LEVELS IN SOUTH CENTRAL COAST AIR BASIN
(SANTA MARIA)
1988–1997
(micrograms per cubic meter - μg/m³)

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
Highest 24-Hour Average	13.9	9.1	11.4	--	--	--	--	--	--	--
Number of Days Exceeding State Standard (25 μg/m³, 24-hour)	0	0	0	--	--	--	--	--	--	--

Source: California Air Quality Data, Annual Summary, California Air Resources Board

6.2.4.6 Fine Particulates (PM_{10})

Particulates in the air are caused by a combination of wind-blown fugitive dust; particles emitted from combustion sources (usually carbon particles); and organic, sulfate, and nitrate aerosols formed in the air from emitted hydrocarbons, sulfur oxides, and NOx, respectively. In 1984, the ARB adopted standards for fine particulates and phased out the total suspended particulate (TSP) standards that had been in effect until then. PM_{10} standards were substituted for TSP standards because PM_{10} corresponds to the size range of inhalable particulates related to human health. In 1987, EPA also replaced national TSP standards with PM_{10} standards. For air quality planning purposes, San Luis Obispo County is considered to be in attainment of federal PM_{10} standards, but in nonattainment of state standards.

As discussed above, the NAAQS for particulates were further revised by EPA with new standards that went into effect on September 16, 1997. In light of recent court decisions, EPA will delay implementation of the new $PM_{2.5}$ standards for an indefinite period.

Table 6.2-14 shows the federal and state air quality standards for PM_{10}, maximum levels, and geometric and arithmetic annual averages recorded at Morro Bay from 1990, when PM_{10} monitoring began, through 1999. Maximum 24-hour PM_{10} levels exceeded the state standard in 1991, 1993, and 1997, but are consistently lower than the new federal standard based on 99th percentile concentrations. Annual average PM_{10} levels meet both state and federal standards.

The trend of maximum 24-hour average PM_{10} levels is plotted in Figure 6.2-13, and the trend of expected violations of the state 24-hour standard of 50 μg/m³ is plotted in Figure 6.2-14. Note that since PM_{10} is measured only once every six days, expected violation days are six times the number of measured violations.

$PM_{2.5}$ has been measured at only one site in the South Central Coast Air Basin (Arroyo Grande) for only one year (1995). The highest 24-hour average reading recorded was 25 μg/m³, which is well below the federal standard (65 μg/m³) that will be applied to the three-year average 98th percentile reading.

TABLE 6.2-14
PM_{10} LEVELS AT MORRO BAY
1990–1999
(micrograms per cubic meter - μg/m³)

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Highest 24-Hour Average	40	51	38	64	48	40	42	57	33	39
Annual Geometric Mean (State Standard = 30 μg/m³)	24.1	20.0	17.8	18.6	18.3	18.6	16.6	18.6	13.5	14.4
Annual Arithmetic Mean (Federal Standard = 50 μg/m³)	25.8	22.9	19.4	21.2	19.5	22.3	18.7	20.6	14.6	15.7
Number of Days Exceeding:										
State Standard (50 μg/m³, 24-hour)	0	1	0	2	0	0	0	1	0	0
Federal Standard (150 μg/m³, 24-hour)	0	0	0	0	0	0	0	0	0	0

Source: California Air Quality Data, Annual Summary, California Air Resources Board

6.2.4.7 Airborne Lead

Lead in the air results from the combustion of fuels that contain lead. Twenty-five years ago, motor vehicle gasolines contained relatively large amounts of lead compounds used as octane-rating improvers, and ambient lead levels were relatively high. Beginning with the 1975 model year, manufacturers began equipping new automobiles with exhaust catalysts, which were poisoned by the exhaust products of leaded gasoline. Thus, unleaded gasoline became the required fuel for an increasing fraction of new vehicles, and the phaseout of leaded gasoline began. As a result, ambient lead levels decreased dramatically, and for several years San Luis

Obispo County has been in attainment of state airborne lead levels for air quality planning purposes.

Due to the extremely low levels expected, airborne lead has not been monitored in San Luis Obispo County since 1987, and was monitored elsewhere in the South Central Coast Air Basin only through 1989. During 1987–1989, the closest monitoring site was at Lompoc, in Santa Barbara County. Lead levels at Lompoc are presented in Table 6.2-15. In the years prior to 1988, airborne lead levels at San Luis Obispo and at Lompoc were of similar magnitudes; therefore, the levels shown in Table 6.2-15 are considered typical of those that actually occur at the Project site, i.e., well below the state standard.

TABLE 6.2-15
AIRBORNE LEAD LEVELS IN SOUTH CENTRAL COAST AIR BASIN (LOMPOC)
1988–1997
(micrograms per cubic meter - μg/m³)

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
Highest Monthly Average	.06	.06	--	--	--	--	--	--	--	--
Number of Days Exceeding State Standard (1.5 μg/m³, monthly)	0	0	--	--	--	--	--	--	--	--

Source: California Air Quality Data, Annual Summary, California Air Resources Board

6.2.5 REGULATORY SETTING

Applicable federal, state, and local laws, ordinances, regulations and standards that govern air quality and air pollution are discussed in this section. Specific requirements are identified and the compliance of the proposed Project with these requirements is demonstrated. Applicable LORS are summarized in a table at the end of this regulatory setting. The table also identifies the specific sections in the AFC that demonstrate compliance.

6.2.5.1 Laws, Ordinances, Regulations and Standards (LORS)

Each level of government has adopted specific regulations that limit emissions from electrical power generation facilities and are applicable to this Project. The agencies with air quality permitting authority for this Project are shown in Table 6.2-16. The authority, purpose, and administering agency for each of these are discussed in more detail below.

TABLE 6.2-16
AIR QUALITY AGENCIES

AGENCY	AUTHORITY	CONTACT
U.S. EPA Region IX	PSD permit issuance, enforcement	Gerardo Rios, Chief Permits Office U.S. EPA Region IX 75 Hawthorne Street San Francisco, CA 94105 (415) 744-1259
California Air Resources Board	Regulatory oversight	Ray Menebroker, Chief Project Assessment Branch California Air Resources Board 2020 L Street Sacramento, CA 95814 (916) 322-6026
San Luis Obispo County Air Pollution Control District	Permit issuance, enforcement	Robert W. Carr Air Pollution Control Officer San Luis Obispo County Air Pollution Control District 2156 Sierra Way, Suite B San Luis Obispo, CA 93401 (805) 781-5912

An application for a Determination of Compliance will be filed with the District within approximately one week of filing the AFC. An application for a PSD permit will be filed with EPA Region IX at approximately the same time.

6.2.5.1.1 Federal

The EPA implements and enforces the requirements of many of the federal environmental laws. EPA Region IX, which has its offices in San Francisco, administers EPA programs in California. The federal Clean Air Act, as most recently amended in 1990, provides EPA with the legal authority to regulate air pollution from stationary sources such as MBPP. EPA has promulgated the following stationary source regulatory programs to implement the requirements of the 1990 Clean Air Act:

- Standards of Performance for New Stationary Sources (NSPS)
- National Emission Standards for Hazardous Air Pollutants (NESHAPS)
- Prevention of Significant Deterioration (PSD)
- New Source Review (NSR)

- Title IV: Acid Deposition Control
- Title V: Operating Permits

National Standards of Performance for New Stationary Sources

Authority: Clean Air Act §111, 42 USC §7411; 40 CFR Part 60, Subpart GG

Purpose: Establishes standards of performance to limit the emission of criteria pollutants (air pollutants for which EPA has established national ambient air quality standards (NAAQS)) from new or modified facilities in specific source categories. The applicability of these regulations depends on the equipment size; process rate; and/or the date of construction, modification, or reconstruction of the affected facility. Only the Standards of Performance for Stationary Gas Turbines, which limit NOx and SO_2 emissions from subject equipment, are applicable to the Project. These standards are implemented at the local level with federal and state oversight.

Administering Agency: San Luis Obispo County Air Pollution Control District (SLOCAPCD), with EPA Region IX and CARB oversight.

National Emission Standards for Hazardous Air Pollutants

Authority: Clean Air Act § 112, 42 USC §7412; 40 CFR Part 63

Purpose: Establishes national emission standards to limit emissions of hazardous air pollutants (HAPs, or air pollutants identified by EPA as causing or contributing to the adverse health effects of air pollution but for which NAAQS have not been established) from facilities in specific source categories. Requires the use of maximum achievable control technology (MACT) for major sources of HAPs that are not specifically regulated or exempted under Part 63. Standards are implemented at the local level with federal oversight. NESHAPS promulgated pursuant to Section 112 of the Clean Air Act are not applicable to the Project because no specific standards have been established and the facility is not a major source of HAPs; thus NESHAPs requirements will not be addressed further.

Prevention of Significant Deterioration Program

Authority: Clean Air Act §160-169A, 42 USC §7470-7491; 40 CFR Parts 51 and 52

Purpose: Requires preconstruction review and permitting of new or modified major stationary sources of air pollution to prevent significant deterioration of ambient air quality. Prevention of Significant Deterioration (PSD) applies to pollutants for which ambient concentrations do not exceed the corresponding NAAQS (i.e., attainment pollutants). The PSD program allows new sources of air pollution to be constructed, or existing sources to be modified, while preserving the existing ambient air quality levels, protecting public health and welfare, and protecting Class I areas (e.g., national parks and wilderness areas).

Administering Agency: EPA Region IX.

New Source Review

Authority: Clean Air Act §171-193, 42 USC §7501 et seq.; 40 CFR Parts 51 and 52

Purpose: Requires preconstruction review and permitting of new or modified major stationary sources of air pollution to allow industrial growth without interfering with the attainment and maintenance of ambient quality standards. This program is implemented at the local level with EPA oversight.

Administering Agency: SLOCAPCD, with EPA Region IX oversight.

Title IV - Acid Rain Program

Authority: Clean Air Act §401, 42 USC §7651 et seq.; 40 CFR Part 72

Purpose: Requires the reduction of emissions of acidic compounds and their precursors. The principal source of these compounds is the combustion of fossil fuels. Therefore, Title IV established national standards to limit SO_2 and NOx emissions from electrical power generating facilities. These standards are implemented at the local level with federal oversight.

Administering Agency: SLOCAPCD, with EPA Region IX oversight.

Title V - Operating Permits Program

Authority: Clean Air Act § 501 (Title V), 42 USC §7661; 40 CFR Part 70

Purpose: Requires the issuance of operating permits that identify all applicable federal performance, operating, monitoring, recordkeeping, and reporting requirements. Title V applies to major facilities, Phase II acid rain facilities, subject solid waste incinerator facilities, and any facility listed by EPA as requiring a Title V permit. These requirements are implemented at the local level with federal oversight.

Administering Agency: SLOCAPCD, with EPA Region IX oversight.

6.2.5.1.2 State

The ARB was created in 1968 by the Mulford-Carrell Air Resources Act, through the merger of two other state agencies. ARB's primary responsibilities are to develop, adopt, implement, and enforce the state's motor vehicle pollution control program; to administer and coordinate the state's air pollution research program; to adopt and update, as necessary, the state's ambient air quality standards; to review the operations of the local air pollution control districts; and to review and coordinate preparation of the State Implementation Plan (SIP) for achievement of the federal ambient air quality standards.

State Implementation Plan

Authority: Health & Safety Code (H&SC) §39500 et seq.

Purpose: Required by the federal Clean Air Act, the SIP must demonstrate the means by which all areas of the state will attain and maintain NAAQS within the federally mandated deadlines. ARB reviews and coordinates preparation of the SIP. Local districts must adopt new rules (and/or revise existing rules) and demonstrate that the resulting emission reductions, in conjunction with reductions in mobile source emissions, will result in the attainment of NAAQS. The relevant SLOCAPCD Rules and Regulations that have also been incorporated into the SIP are discussed with the local LORS.

Administering Agency: SLOCAPCD, with ARB and EPA Region IX oversight.

California Clean Air Act

Authority: H&SC §40910 - 40930

Purpose: Established in 1989, the California Clean Air Act requires local districts to attain and maintain both national and state ambient air quality standards at the "earliest practicable date." Local districts must prepare air quality plans demonstrating the means by which the ambient air quality standards will be attained and maintained. The SLOCAPCD Air Quality Plan is discussed with the local LORS.

Administering Agency: SLOCAPCD, with ARB oversight.

Toxic Air Contaminant Program

Authority: H&SC §39650 - 39675

Purpose: Established in 1983, the Toxic Air Contaminant Identification and Control Act created a two-step process to identify toxic air contaminants and control their emissions. ARB identifies and prioritizes the pollutants to be considered for identification as toxic air contaminants. ARB assesses the potential for human exposure to a substance, while the Office of Environmental Health Hazard Assessment evaluates the corresponding health effects. Both agencies collaborate in the preparation of a risk assessment report, which concludes whether a substance poses a significant health risk and should be identified as a toxic air contaminant. In 1993, the Legislature amended the program to identify the 189 federal hazardous air pollutants as toxic air contaminants. ARB reviews the emission sources of an identified toxic air contaminant and, if necessary, develops air toxics control measures to reduce the emissions. There have been no measures adopted via the Toxic Air Contaminant Program that are applicable to the Project.

Air Toxic "Hot Spots" Act

Authority: CA Health & Safety Code § 44300-44384; 17 CCR §93300-93347

Purpose: Established in 1987, the Air Toxics "Hot Spots" Information and Assessment Act supplements the toxic air contaminant program, by requiring the development of a statewide inventory of air toxics emissions from stationary sources. The program requires affected facilities to prepare (1) an emissions inventory plan that identifies relevant air toxics and sources of air toxics emissions; (2) an emissions inventory report quantifying air toxics emissions; and (3) a health risk assessment, if necessary, to characterize the health risks to the exposed public. Facilities whose air toxics emissions are deemed to pose a significant health risk must issue notices to the exposed population. In 1992, the Legislature amended the program to further require facilities whose air toxics emissions are deemed to pose a significant health risk to implement risk management plans to reduce the associated health risks. This program is implemented at the local level with state oversight.

Administering Agency: SLOCAPCD, with ARB oversight.

CEC and ARB Memorandum of Understanding

Authority: CA Pub. Res. Code § 25523(a); 20 CCR §1752, 1752.5, 2300-2309, and Div. 2, Chap. 5, Art. 1, Appendix B, Part (k)

Purpose: Establishes requirements in the CEC's decision-making process on an application for certification that assure protection of environmental quality.

Administering Agency: California Energy Commission.

6.2.5.1.3 Local

When the state's air pollution statutes were reorganized in the mid-1960s, local districts were required to be established in each county of the state. There are three different types of districts: county (including the SLOAPCD), regional, and unified. Local districts have principal responsibility for developing plans for meeting the NAAQS and California ambient air quality standards; for developing control measures for nonvehicular sources of air pollution necessary to achieve and maintain both state and federal air quality standards; for implementing permit programs established for the construction, modification, and operation of sources of air pollution; for enforcing air pollution statutes and regulations governing nonvehicular sources; and for developing programs to reduce emissions from indirect sources.

San Luis Obispo County Air Pollution Control District Clean Air Plan

Authority: H&SC §40914

Purpose: The SLOCAPCD plan defines the proposed strategies, including stationary source and transportation control measures and new source review rules, whose implementation will attain and maintain the state ambient air quality standards. The relevant stationary source control measures and new source review requirements are discussed with SLOCAPCD Rules and Regulations.

Administering Agency: SLOCAPCD, with ARB oversight.

San Luis Obispo County Air Pollution Control District Rules and Regulations

Authority: H&SC §4000 et seq., H&SC §40200 et seq., indicated SLOCAPCD Rules

Purpose: Establishes procedures and standards for issuing permits; establishes standards and limitations on a source-specific basis.

Administering Agency: SLOCAPCD with EPA and ARB oversight.

6.2.5.2 Summary of Applicable Requirements

This section summarizes applicable federal, state, and local air pollution requirements.

6.2.5.2.1 Authority to Construct

Rule 201 (Permits) specifies that any facility installing nonexempt equipment that causes or controls the emission of air pollutants must first obtain an Authority to Construct from the SLOCAPCD. Under Rule 223 (Power Plants), the Commission Decision acts as an authority to construct for a power plant.

6.2.5.2.2 Review of New or Modified Sources

Rule 204 (Requirements) implements the federal NSR program, as well as the new source review requirements of the California Clean Air Act. The rule contains the following elements:

- Best available control technology (BACT);
- Emission offsets; and
- Air quality impact analysis (AQIA).

Best Available Control Technology

BACT must be applied to any new or modified source resulting in an emissions increase exceeding any SLOCAPCD BACT threshold shown in Table 6.2-17. Reasonably available control technology (RACT) must be applied to any new or modified source resulting in an emissions increase not exceeding any of the indicated BACT thresholds.

TABLE 6.2-17
SLOCAPCD BACT EMISSION THRESHOLDS

POLLUTANT	THRESHOLD (lb/day)
PM	25
NOx	25
SO_2	25
VOC	25
CO	250

The SLOCAPCD defines BACT as the most stringent emission limitation or control technique that:

- has been achieved in practice for such permit unit category or class of source; or
- is contained in any approved state implementation plan for such permit unit category or class of source. A specific limitation or control technique shall not apply if the owner or operator of the proposed permit unit demonstrates to the satisfaction of the air Pollution Control Officer that such limitation or control technique is not presently achievable; or
- is any other emission limitation or control technique, including process and equipment changes of basic and control equipment, found by the air Pollution control Officer to be technologically feasible for such class or category of sources or for a specific source, and cost-effective as compared to measures listed in the Clean Air Plant or rules adopted by the Board.

The SLOCAPCD defines RACT as the lowest emission limit achievable through the application of control technology that is reasonably available, considering technological and economic feasibility.

Emission Offsets

A new or modified facility with emissions exceeding the SLOCAPCD offset thresholds shown in Table 6.2-18 must offset all emissions increases at a 1:1 ratio.

TABLE 6.2-18
SLOCAPCD OFFSET EMISSION THRESHOLDS

POLLUTANT	THRESHOLD (tpy)
PM_{10}	25
NOx	25
SO_2	25
VOC	25
CO	250

Air Quality Impact Analysis

An air quality impact analysis must be conducted to evaluate impacts of emission increases from new or modified facilities on ambient air quality. Project emissions must not cause an exceedance of any ambient air quality standard.

Toxics New Source Review

Rule 219 provides a mechanism for evaluating potential impacts of air emissions of toxic substances from new, modified and relocated sources in the SLOCAPCD. The rule requires a demonstration that the source will not adversely impact the health and welfare of the public.

CEC Review

Rule 223 establishes a procedure for coordinating SLOCAPCD review of power plant projects with the CEC AFC process. Under Rule 223, the SLOCAPCD reviews the AFC and issues a Determination of Compliance for a proposed project, which is equivalent to an Authority to Construct. A permit to operate is issued following the CEC's certification of a project.

6.2.5.2.3 Prevention of Significant Deterioration

The PSD requirements apply, on a pollutant-specific basis, to any project that is a new major stationary source or a major modification to an existing major stationary source. A major source is a listed facility (one of 28 PSD source categories listed in the federal Clean Air Act) that emits at least 100 tpy or any facility that emits at least 250 tpy. A modified major source is subject to PSD if the cumulative emission increase since the applicable PSD baseline dates exceeds the PSD thresholds shown in Table 6.2-19.

TABLE 6.2-19
PSD EMISSION THRESHOLDS FOR A MAJOR MODIFICATION

POLLUTANT	THRESHOLD (tpy)
PM_{10}	15
NOx	40
SO_2	40
VOC	40
CO	100

The PSD program contains the following elements:

- Air quality monitoring;
- BACT;
- Air quality impact analysis;
- Protection of Class I areas; and
- Visibility, soils, and vegetation impacts.

Air Quality Monitoring

EPA may, at its discretion, require preconstruction and/or post-construction ambient air quality monitoring. Preconstruction monitoring data must be gathered over a one-year period to characterize local ambient air quality. Post-construction air quality monitoring data must be collected as deemed necessary by EPA to characterize the impacts of project emissions on ambient air quality.

Best Available Control Technology

BACT must be applied to any modified major source to minimize the emissions of those pollutants exceeding the PSD emission thresholds. EPA defines BACT as an emissions limitation based on the maximum degree of reduction for each subject pollutant, considering energy, environmental, and economic impacts, that is achievable through the application of available methods, systems, and techniques. BACT must be as stringent as any emission limit required by an applicable NSPS or NESHAP.

Air Quality Impact Analysis

An air quality dispersion analysis must be conducted to evaluate impacts of significant emission increases from new or modified facilities on ambient air quality. Project emissions must not cause an exceedance of any ambient air quality standards, and the increase in ambient air concentrations must not exceed the allowable increments shown in Table 6.2-20.

TABLE 6.2-20
PSD CLASS II INCREMENTS

POLLUTANT	AVERAGING PERIOD	ALLOWABLE INCREMENT (ug/m^3)
PM_{10}	Annual 24-Hour	17 30
NOx	Annual	25
SO_2	Annual 24-Hour 3-Hour	20 91 512

Protection of Class I Areas

The increase in ambient air quality concentrations for the relevant pollutants (i.e., NOx, PM_{10}, SO_2, TSP, or ROGs) within Class I locations must be characterized if there is a significant emission increase associated with the new or modified source.

Visibility, Soils, and Vegetation Impacts

Impairment to visibility, soils, and vegetation resulting from Project emissions as well as associated commercial, residential, industrial, and other growth must be analyzed. Cumulative impacts to local ambient air quality must also be analyzed.

6.2.5.2.4 Acid Rain Permit

Rule 217 (Federal Part 72 Permits) requires that a subject facility comply with maximum operating emissions levels for SO_2 and NOx, and must monitor SO_2, NOx, and CO_2 emissions and exhaust gas flow rates. A Phase II acid rain facility, such as MBPP, must also obtain an acid rain permit as mandated by Title IV of the 1990 Clean Air Act Amendments. A permit application must be submitted to the SLOCAPCD at least 24 months before operation of the new unit commences. The application must present all relevant Phase II sources at the facility, a compliance plan for each unit, applicable standards, and an estimated commencement date of operations.

6.2.5.2.5 Federal Operating Permit

Rule 216 (Federal Part 70 Permits) requires major facilities and Phase II acid rain facilities undergoing modifications to obtain an operating permit containing the federally enforceable requirements mandated by Title V of the 1990 Clean Air Act Amendments. A permit application for a modification to an existing facility must be submitted to the SLOCAPCD, and a revised Title V permit issued, prior to operation of the modified facility. The application must present a process description, all stationary sources at the facility, applicable regulations, estimated emissions, associated operating conditions, alternative operating scenarios, a facility compliance plan, and a compliance certification.

6.2.5.2.6 New Source Performance Standards

Rule 601 (New Source Performance Standards) requires compliance with applicable federal standards of performance for new or modified stationary sources.

Subpart GG (Standards of Performance for Stationary Gas Turbines) applies to gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (Gj/hr) (10.15 MMBtu/hr) at higher heating value. The proposed new turbines at MBPP have hourly heat input that exceed this threshold. The NSPS NOx emission limit is defined by the following equation:

$$STD = \frac{0.0150\ (14.4)}{Y} + F$$

where:	STD	=	allowable NOx emissions (percent by volume at 15% O_2 on a dry basis)
	Y	=	manufacturer's rated heat rate at peak load (kilojoules per watt hour)
	F	=	NOx emission allowance for fuel-bound nitrogen (assumed to be zero for natural gas)

Subpart Da (Standards of Performance for Electric Utility Steam Generating Units) applies to electric utility boilers and steam generating units that are capable of combusting more than 250 MMBtu per hour of fossil fuel. The maximum duct burner heat input exceeds this threshold. Subpart Da contains emissions standards for particulate matter, SO_2, and NOx from these units.

6.2.5.2.7 SLOCAPCD Prohibitory Rules

The general prohibitory rules of the SLOCAPCD applicable to the MBPP Project include the following:

- Rule 401 – Visible Emissions: Prohibits visible emissions as dark or darker than Ringelmann No. 2 for periods greater than three minutes in any hour.
- Rule 402 – Nuisance: Prohibits the discharge from a facility of air pollutants that cause injury, detriment, nuisance, or annoyance to the public, or that damage business or property.
- Rule 403 – Particulate Matter Emission Standards: Prohibits PM emissions in excess of 10 lb/hr or 0.3 grains per dry standard cubic foot (gr/dscf).
- Rule 404 – Sulfur Compounds Emission Standards, Limitations, and Prohibitions: Prohibits sulfur compound emissions, calculated as SO_2, in excess of 200 lb/hr or 0.2% (2,000 ppm) from any source. The maximum exhaust SO_2 emission rate (1.12 lb/hr) and concentration (0.12 ppm) will be well below the Rule 404 SO_2 emission limits. This rule also prohibits the burning of any gaseous fuel containing sulfur compounds, calculated as hydrogen sulfide, in excess of 0.5 gr/dscf of fuel.
- Rule 405 – Nitrogen Oxides Emission Standards, Limitations, and Prohibitions: Prohibits emissions of NOx (calculated as NO_2) in excess of 140 lb/hr.
- Rule 406 – Carbon Monoxide Emission Standards and Limitations: Prohibits CO emissions in excess of 2,000 ppm from any source.
- Rule 429 – Oxides of Nitrogen and Carbon Monoxide Emissions from Electric Power Generation Boilers: Limits NOx and CO emissions from and phases out fuel oil use in electric power generation boilers.

TABLE 6.2-21
LAWS, ORDINANCES, REGULATIONS, STANDARDS (LORS), AND PERMITS FOR PROTECTION OF AIR QUALITY

LORS	PURPOSE	REGULATING AGENCY	PERMIT OR APPROVAL	SCHEDULE AND STATUS OF PERMIT	CONFORMANCE (SECTION)
Federal					
Clean Air Act (CAA) §160-169A and implementing regulations, Title 42 United States Code (USC) §7470-7491 (42 USC §7470-7491), Title 40 Code of Federal Regulations (CFR) Parts 51 & 52 (40 CFR Parts 51 & 52). (Prevention of Significant Deterioration Program)	Requires prevention of significant deterioration (PSD) review and facility permitting for construction of new or modified major stationary sources of air pollution. PSD review applies to pollutants for which ambient concentrations are lower than NAAQS.	EPA	Issues Prevention of Significant Deterioration Permit for a Major Modification to an Existing Major Source.	Permit to be obtained before start of construction.	6.2.6.3.3, 6.2.6.5, 6.2.7.1 Pages 6.2-60 – 66, 6.2-68– 70, 6.2-71 – 73
CAA §171-193, 42 USC §7501 et seq. (New Source Review)	Requires new source review (NSR) facility permitting for construction or modification of specified stationary sources. NSR applies to pollutants for which ambient concentration levels are higher than NAAQS.	SLOCAPCD with EPA oversight	After project review, issues DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	6.2.6.3.2, 6.2.7.3 Pages 6.2-55 – 59, 6.2-73– 78
CAA §401 (Title IV), 42 USC §7651 (Acid Rain Program)	Requires reductions in NOx and SO_2 emissions.	SLOAPCD with EPA oversight	Issues Acid Rain permit after review of application.	Permit to be obtained prior to commencement of operation	6.2.7.3 Page 6.2-77
CAA §501 (Title V), 42 USC §7661 (Federal Operating Permits Program)	Establishes comprehensive permit program for major stationary sources.	SLOCAPCD with EPA oversight	Issues Title V permit after review of application.	Permit to be obtained prior to commencement of construction.	6.2.7.3 Page 6.2-77
CAA §111, 42 USC §7411, 40 CFR Part 60 (New Source Performance Standards – NSPS)	Establishes national standards of performance for new stationary sources.	SLOCAPCD with EPA oversight	After project review, issues DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	6.2.7.3 Page 6.2-78

TABLE 6.2-21
LAWS, ORDINANCES, REGULATIONS, STANDARDS (LORS), AND PERMITS FOR PROTECTION OF AIR QUALITY

LORS	PURPOSE	REGULATING AGENCY	PERMIT OR APPROVAL	SCHEDULE AND STATUS OF PERMIT	CONFORMANCE (SECTION)
State					
H&SC §44300-44384; California Code of Regulations (CCR) §93300-93347 (Toxic "Hot Spots" Act)	Requires preparation and biennial updating of facility emission inventory of hazardous substances; risk assessments.	SLOCAPCD with CARB oversight	After project review, issues DOC with conditions limiting emissions.	Screening HRA submitted as part of AFC.	6.2.6.4 Pages 6.2-66 – 67
California Public Resources Code §25523(a); 20 CCR §§1752, 2300-2309 (CEC & CARB Memorandum of Understanding)	Requires that CEC's decision on AFC include requirements to assure protection of environmental quality; AFC required to address air quality protection.	CEC	After project review, issues Final Certification with conditions limiting emissions.	SLOCAPCD approval of AFC, i.e., DOC, to be obtained prior to CEC approval.	6.2.7.3 Page 6.2-73
Local					
SLOAPCD Rule 204 (Review of New or Modified Sources)	NSR: Requires that preconstruction review be conducted for all proposed new or modified sources of air pollution, including BACT, emissions offsets, and air quality impact analysis.	SLOCAPCD with ARB oversight	After project review, issues DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	6.2.6.3.2, 6.2.7.3 Pages 6.2-57 – 60, 6.2-73—78
SLOCAPCD Rule 216 (Federal Operating Permits)	Implements operating permits requirements of CAA Title V.	SLOCAPCD with EPA oversight	Issues Title V permit after review of application.	Agency approval to be obtained before start of construction.	6.2.7.3 Page 6.2-77
SLOCAPCD Rule 217 (Acid Deposition Control)	Implements acid rain regulations of CAA Title IV.	SLOCAPCD with EPA oversight	Issues Title IV permit after review of application.	Application to be made within 12 months of start of facility operation.	6.2.7.3 Page 6.2-77
SLOCAPCD Rule 219 (Toxics New Source Review)	Requires risk assessments for all proposed new or modified sources of toxic air contaminants.	SLOCAPCD	After project review, issues DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	6.2.6.4.2, App. 6.2-4 Pages 6.2-67 – 68
SLOCAPCD Rule 401 (Visible Emissions)	Limits visible emissions to no darker than Ringelmann No. 2 for periods greater than 3 minutes in any hour.	SLOCAPCD with ARB oversight	After project review, issues DOC with conditions limiting emissions.	Agency approval to be obtained prior to commencement of operation.	6.2.7.3 Page 6.2-78

TABLE 6.2-21
LAWS, ORDINANCES, REGULATIONS, STANDARDS (LORS), AND PERMITS FOR PROTECTION OF AIR QUALITY

LORS	PURPOSE	REGULATING AGENCY	PERMIT OR APPROVAL	SCHEDULE AND STATUS OF PERMIT	CONFORMANCE (SECTION)
SLOCAPCD Rule 402 (Public Nuisance)	Prohibits emissions in quantities that adversely affect public health, other businesses, or property.	SLOCAPCD with ARB oversight	After project review, issues DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	6.2.7.3 Page 6.2-78
SLOCAPCD Rule 403 (Particulate Matter)	Limits PM emissions from stationary sources.	SLOCAPCD with ARB oversight	After project review, issues DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	6.2.7.3 Page 6.2-78
SLOCAPCD Rule 404 (Sulfur Compounds Emissions)	Limits SO_2 emissions from stationary sources.	SLOCAPCD with ARB oversight	After project review, issues DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	6.2.7.3 Page 6.2-78
SLOCAPCD Rule 405 (Nitrogen Oxides)	Limits NOx emissions from stationary sources.	SLOCAPCD with ARB oversight	After project review, issues DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	6.2.7.3 Page 6.2-78
SLOCAPCD Rule 406 (Carbon Monoxide)	Limits CO emissions from stationary sources.	SLOCAPCD with ARB oversight	After project review, issues DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	6.2.7.3 Page 6.2-78
SLOCAPCD Rule 429 (Emissions from Electric Power Generation Boilers)	Limits NOx, CO, and ammonia emissions from electric power generation boilers.	SLOCAPCD with ARB oversight	After project review, issues DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	6.2.7.3 Page 6.2-78
SLOCAPCD Rule 601 (New Source Performance Standards,: 40 CFR 60, Subpart GG, Stationary Gas Turbines; Subpart Da,Utility Boilers)	Requires monitoring of fuel, other operating parameters; limits NOx and SO_2 and PM emissions, requires source testing, emissions monitoring, and recordkeeping.	SLOCAPCD with ARB oversight	After project review, issues DOC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	6.2.7.3 Page 6.2-78

6.2.6 IMPACTS

6.2.6.1 Overview of the Analytical Approach to Estimating Facility Impacts

The facility is subject to SLOCAPCD Rules 202 and 204, which contain the District's New Source Review (NSR) and permitting requirements, and to the requirements of 40 CFR 52.21. As discussed in Section 6.2.5 of the application, the federal EPA retains the authority for issuing PSD permits for projects in the SLOCAPCD.

The District NSR regulation requires that BACT be used, emission offsets be provided, and an air quality impact analysis be performed. Similarly, the federal PSD regulation requires the use of BACT, and various analyses of the air quality impacts of the proposed Project. Ambient air quality impact analyses have been conducted to satisfy District and EPA requirements, as well as CEC requirements, for criteria pollutants (NO_2, CO, PM_{10}, and SO_2), noncriteria pollutants, and construction impacts. The applicability of the District regulatory requirements and facility compliance with these requirements are based on facility emission levels and ambient air quality impact analyses.

Maximum pollutant emission rates and ambient impacts of the Project have been evaluated to determine compliance with District and federal regulations. Emissions sources include four new gas turbines and four fired heat recovery steam generators (HRSGs). The four existing boilers at the facility will be retired after startup of the new units. Actual operation of the turbines will range between 50% and 100% of maximum rated output. Emission control systems will be fully operational except during startups and shutdowns. Maximum annual emissions are based on operation of the facility at maximum firing rates, and include the expected maximum hours of startups and shutdowns that may occur in a year. Each turbine startup will result in transient emission rates until steady-state operation for the gas turbine and emission control systems is achieved.

The criteria pollutant ambient impact analyses use pollutant-specific maximum hourly, daily, and annual emission rates from the facility. This allows calculation of maximum ambient impacts for each pollutant and averaging period. The following sections describe the emission sources that have been evaluated for the facility, the analyses of ambient impacts, and the evaluation of facility compliance with the applicable air quality regulations.

6.2.6.2 Facility Emissions

6.2.6.2.1 Reductions in Emissions from the Existing Facility

MBPP consists of four utility boilers: Units 1 and 2, which are rated at 170 MW (gross) each; and Units 3 and 4, which are rated at 345 MW (gross) each. All four units will be shut down once the new turbines are operational, resulting in emissions reductions. Emissions reductions are calculated differently under District and federal regulations and for CEQA purposes. Each approach is discussed separately below.

District Regulations

Under the District's new source review regulation, emissions increases and reductions are calculated separately, and the reductions are used as emission reduction credits (ERCs) to offset all emissions increases. Credits for the shutdown of the boilers are determined using the actual emissions from the units over a representative three-year period, adjusted to reflect best available retrofit control technology (BARCT). The most recent three-year period (August 1997 through July 2000) has been proposed as the appropriate baseline period for this calculation. The District has determined that BARCT for Units 1 and 2 is a NOx emission rate of 30 ppm, corrected to 3% O_2, while BARCT for Units 3 and 4 is a NOx emission rate of 10 ppm, corrected to 3% O_2. The calculation of the baseline emissions for the boilers is shown in Appendix 6.2-1, Attachment 6.2-1.1, and in Tables 6.2-1.1 and 1.2. The results of the calculations are summarized in Table 6.2-22.

TABLE 6.2-22
CREDITABLE EMISSIONS REDUCTIONS
UNDER DISTRICT RULE 213
MORRO BAY POWER PLANT[1]

	EMISSIONS, tons per year				
	NOx	SO_2	CO	VOC	PM_{10}
Unit 1	51.1	0.82	57.1	7.5	10.4
Unit 2	60.0	0.97	18.8	8.9	12.2
Unit 3	65.6	3.17	539.5	29.1	40.2
Unit 4	69.1	3.34	532.6	30.6	42.3
Total Baseline	245.7	8.31	1,147.9	76.1	105.2
Total Creditable Reductions[2]	245.7	6.64	918.3	60.9	84.2

(1) NOx emissions adjusted for BARCT (see text); CO from CEMS; SO_2 from mass balance; VOC and PM_{10} from AP-42 emission factors.

(2) Some discounting required to calculate creditable ERCs. See Section 6.2.7.3.2.

Federal Regulations

Under federal PSD regulations, the potential to emit for the Project is compared with the actual emissions from the existing emissions units to be modified. In this case, the existing units to be "modified" are Units 1, 2, 3, and 4, which will be shut down. Federal regulations generally define actual emissions as the average emission rate over the two years preceding the date of application that is representative of normal source operation. Therefore, the most recent 24 months of operation (August 1998 through July 2000) have been used to calculate actual emissions. Fuel use and generation data for the existing boilers during the past 24 months are shown in Appendix 6.2-1, Table 6.2-1.1.

As the boilers are being shut down, their creditable emissions reductions are equal to the actual emissions during the baseline period. Federal regulations do not require adjustments of the baseline emissions for BARCT. Calculation of actual emissions during the baseline period is shown in detail in Appendix 6.2-1, Attachment 6.2-1.1. Actual emissions for Units 1, 2, 3, and 4 are summarized in Table 6.2-23 below.

CEQA

For CEQA purposes, the calculation of emissions reductions from the shutdown of the existing boilers is based on a comparison of historical and projected future emissions. Historical emissions during the baseline period for each of the units are the same as those calculated for the PSD evaluation above. Projected future emissions from the boilers, after they have been shut down, are zero. The CEQA baseline for the Project is also shown in Table 6.2-23 below.

TABLE 6.2-23
CALCULATION OF BOILER EMISSIONS
UNDER 40 CFR 52.21 AND CEQA
MORRO BAY POWER PLANT[1]

	EMISSIONS, tons per year				
	NOx	SO_2	CO	VOC	PM_{10}
Actual Emissions (Baseline)					
Unit 1	193.3	1.1	80.0	10.3	14.2
Unit 2	273.5	1.3	24.8	12.2	16.8
Unit 3	170.9	3.7	644.7	33.9	46.9
Unit 4	217.7	3.9	686.5	35.7	49.3
Total	855.4	10.0	1,436.0	92.1	127.2

(1) NOx and CO from CEMS; SO_2 from mass balance; VOC and PM_{10} from AP-42 emission factors.

6.2.6.2.2 New Equipment

As discussed in Section 2 of the AFC, the new equipment will consist of four GE Model 7251FA combustion turbines with duct burners, each rated at 300 megawatts (MW) (net, nominal, at site design conditions, including steam turbine output). Natural gas will be the only fuel used at the facility. Typical specifications for natural gas fuel are shown in Table 6.2-24.

TABLE 6.2-24
TYPICAL NATURAL GAS ANALYSIS
MORRO BAY POWER PLANT

PARAMETER	VALUE
Carbon Dioxide	1.296%
Nitrogen	0.541%
Methane	95.846
Ethane	1.889
Propane	0.307
Iso-Butane	0.035
N-Butane	0.043
Iso-Pentane	0.013
N-Pentane	0.010
Hexane and higher	0.020
Sulfur Content	less than 0.25 gr/dscf
High Heating Value (HHV)	1022 Btu/ft^3 22,412 Btu/lb

Fuel combustion results in the formation of NOx, SO_2, unburned hydrocarbons (VOC), PM_{10}, and CO. The combustion turbines will be equipped with dry low-NOx combustors that act to minimize the formation of NOx and CO. To further reduce gas turbine NOx, selective catalytic reduction (SCR) control systems will be provided. To maintain low CO emissions, oxidation catalyst systems will be installed. Ammonia (NH_3) will be used in the SCR system; therefore, unreacted NH_3 emissions have also been analyzed. Because natural gas is a clean burning fuel, there will be minimal formation of combustion PM_{10} and SO_2.

Criteria Pollutant Emissions

Gas turbine and duct burner emission rates have been estimated from vendor data, facility design criteria, and established emission calculation procedures. Maximum emission rates for the combustion turbines alone are shown in Table 6.2-25; emission rates for the combustion turbines with duct burning are shown in Table 6.2-26. Emission rates and heat iput at minimum and maximum nominal loads and ambient temperatures are shown in Appendix 6.2-1, Table 6.2-1.3.

TABLE 6.2-25
EMISSIONS FROM COMBUSTION TURBINES[1]

Pollutant	ppmvd @ 15% O_2	lb/MMBtu	lb/hr
NOx	2.50[2]	0.0092	16.72
CO	6.00[2]	0.0132	24.41
VOC	2.0[2]	0.0015	2.71
PM_{10}[3,4]	0.0028 gr/dscf	0.00102	11.0
SO_2[5]	0.14	0.0007	1.30

TABLE 6.2-26
EMISSIONS FROM COMBUSTION TURBINES WITH DUCT BURNING[1]

Pollutant	ppmvd @ 15% O_2	lb/MMBtu	lb/hr
NOx	2.50[2]	0.009	19.32
CO	6.00[2]	0.0132	28.26
VOC	2.0[2]	0.0015	5.39
PM_{10}[3,4]	0.0023 gr/dscf	0.0064	13.3
SO_2[5]	0.14	0.0007	1.50

(1) Emission rates shown reflect the highest value at any operating load.
(2) Duke Energy design criteria.
(3) Emission rate provided by vendor. Concentration and emission factor calculated from emission rate.
(4) 100 percent of particulate matter emissions assumed to be emitted as PM_{10}; PM_{10} emissions include both front and back half.
(5) Based on expected fuel sulfur content of 0.25 gr/100 scf fuel.

Maximum emission rates expected to occur during startup and shutdown are shown in Table 6.2-27. PM_{10} and SO_2 emissions have not been included in this table because emissions of these pollutants will be lower during startup and shutdown periods than during baseload facility operation.

TABLE 6.2-27
FACILITY STARTUP/SHUTDOWN EMISSION RATES[1]
MORRO BAY POWER PLANT

	NOx	CO	VOC
Startup/Shutdown, lb/hour	80	620	16
Startup/Shutdown, lb/start[2]	320	2,480	64

(1) Estimated based on vendor data and source test data. See Appendix 6.2-1, Tables 6.2-1.4a and 1.4b.
(2) Maximum of four hours per start.

The maximum firing rate of the gas turbines, daily and annual fuel consumption rates, and operating restrictions are used to calculate maximum potential hourly, daily, and annual emissions for each pollutant. The maximum heat input rates (fuel consumption rates) for the gas turbines are shown in Table 6.2-28. These are based on a maximum of 8,400 operating hours per year, per turbine; the turbine will be in startup and/or shutdown mode for up to 400 of these hours. Calculations are shown in Appendix 6.2-1, Table 6.2-1.5.

TABLE 6.2-28
MAXIMUM TURBINE HEAT INPUT RATES (HHV), NOT TO BE EXCEEDED[1]

PERIOD	TOTAL FUEL USE FOR FOUR TURBINES WITH DUCT FIRING		GAS TURBINE WITH DUCT FIRING, each		GAS TURBINES, each[1]	
Per Hour	8,564.8	MMBtu/hr	2,141.2	MMBtu/hr	1,850.4	MMBtu/hr
Per Day	196,250	MMBtu/day	34,259.2	MMBtu/day	14,803.2	MMBtu/day
Per Year	66,826,240	MMBtu/yr	8,564,800	MMBtu/yr	8,141,760	MMBtu/yr

(1) Based on maximum heat input for full load operation at 33 deg. F.

Maximum hourly, daily and annual emissions were determined by evaluating the following operating cases for hourly, daily, and annual operations.

Maximum Hourly Emissions:

- Two turbines are in startup mode.
- Two turbines operate at full load with duct firing.

Maximum Daily Emissions:

For NOx, CO, and VOC:

- Each turbine has four hours of startup.
- Each turbine operates at full load with duct firing for 16 hours.
- Each turbine operates at full load without duct firing for the remaining hours.

For SO_2 and PM_{10}:

- Each turbine operates at full load with duct firing for 16 hours.
- Each turbine operates at full load without duct firing for 8 hours.

Maximum Annual Emissions:

For NOx, CO, and VOC:

- Each turbine has 400 hours of startups per year.
- Each turbine operates at full load with duct firing for 4,000 hours.
- Each turbine operates at full load without duct firing for the remaining 4,000 hours.

For SO_2 and PM_{10}:

- Each turbine operates at full load with duct burning for 4,000 hours per year.
- Each turbine operates at full load without duct firing for 4,400 hours per year.

The maximum annual, daily, and hourly emissions for the new turbines are shown in Table 6.2-29. Detailed emission calculations appear in Appendix 6.2-1, Table 6.2-1.6.

TABLE 6.2-29
EMISSIONS FROM NEW TURBINES[1]

	NOx	SO_2	CO	VOC	PM_{10}
Maximum Hourly Emissions, lb/hr	198.6	5.8	1,296.5	42.8	53.2
Maximum Daily Emissions, lb/day	2,784.0	134.4	12,119.2	644.3	1203.2
Maximum Quarterly Emissions, tons/qtr	73.1	5.8	229.3	19.4	50.8
Maximum Annual Emissions, tpy	292.3	23.0	917.4	77.6	203.2

(1) Total, four turbines. See Appendix 6.2-1, Table 6.2-1.6 for calculations. Includes startup emissions.

Net Emissions Increase

As discussed above, the net emissions increase from the proposed modification is calculated differently for District and federal regulatory purposes and under CEQA. Under the District regulations, the net emissions increase is calculated as the sum of all of the increases in emissions from each emissions unit resulting from the Project. Since the only emissions units with an increase in emissions are the new turbines, the net emissions increase under District regulations is equal to the emissions from the new turbines, as shown in Table 6.2-30.

TABLE 6.2-30
NET EMISSIONS INCREASE UNDER DISTRICT RULE 213.D.2 (tons per year)

	NOx	SO_2	CO	VOC	PM_{10}
New Gas Turbines	292.3	23.0	917.4	77.6	203.2
Net Increase	292.3	23.0	917.4	77.6	203.2

For federal PSD and CEQA purposes, the net emissions increase is calculated as the difference between the actual emissions from the existing boilers and future emissions from the new turbines (from Table 6.2-29). This calculation is shown in Table 6.2-31 below.

TABLE 6.2-31
NET EMISSIONS INCREASE UNDER 40 CFR 52.21 AND CEQA
(tons per year)

	NOx	SO_2	CO	VOC	PM_{10}
New Gas Turbines	292.3	23.0	917.4	77.6	203.2
Total Baseline	855.4	10.0	1,436.0	92.1	127.2
Net Emissions Increase (Reduction)	(563.0)	13.0	(518.7)	(14.5)	76.0

Noncriteria Pollutant Emissions

Noncriteria pollutants are substances that have been identified as pollutants that may cause adverse human health effects. Nine of these pollutants are regulated under the federal New Source Review program: lead, asbestos, beryllium, mercury, fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds. In addition to these nine substances, EPA has listed 189 compounds as potential hazardous air pollutants (Clean Air Act Sec.112(b)(1)); many of these are also regulated under the California Air Toxics "Hot Spots" Act. Any pollutant that may be emitted from the facility and is on the federal New Source Review list, the federal Clean Air Act list, and/or the Toxics "Hot Spots" list has been evaluated. Emission factors were determined by reviewing the available technical data, determining the products of combustion, and/or using material balance calculations.

Noncriteria pollutant emission factors for existing equipment at the power plant were based on source testing and taken from the AB2588 health risk assessment (PG&E, 1991).* Emission factors for the new turbines were taken from source test data, from data compiled by the Ventura County APCD, and from the CATEF database. Appendix 6.2-1, Tables 6.2-1.7, 1.8 and 1.9 provide the detailed emission calculations for noncriteria pollutants. Noncriteria pollutant emissions from the boilers and turbines are summarized in Tables 6.2-32 and 6.2-33, respectively. As emissions of each individual HAP are below 10 tons per year and total HAP emissions are below 25 tons per year, the turbines are not subject to the MACT requirements of 40 CFR Part 63.

* Additional sources included in the screening health risk assessment consist of three Diesel-fueled fire pump engines, a Diesel-fueled emergency generator, gasoline storage and dispensing activities and boiler chemical charging.

TABLE 6.2-32
HISTORICAL ACTUAL NONCRITERIA POLLUTANT EMISSIONS FROM BOILERS
MORRO BAY POWER PLANT

POLLUTANT	BOILERS 1 AND 2 (TOTAL)		BOILER 3		BOILER 4	
	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
Benzene	4.03E-3	<0.01	4.14E-3	<0.01	4.14E-3	<0.01
Formaldehyde	4.23E-2	3.8E-2	4.35E-2	6.7E-2	4.35E-2	7.1E-2

Table 6.2-33
NONCRITERIA POLLUTANT EMISSIONS FROM NEW GAS TURBINES
MORRO BAY POWER PLANT

POLLUTANT	GAS TURBINES (each)		TOTAL, FOUR GAS TURBINES (ton/yr)
	lb/hr	ton/yr	
Acetaldehyde	0.14	0.56	2.24
Acrolein	1.35E-2	0.05	0.21
Ammonia (1)	14.3	60.1	240.4
Benzene	2.85E-2	0.11	0.44
1,3-Butadiene	2.66E-4	1.04E-3	4.15E-3
Ethylbenzene	3.75E-2	0.15	0.59
Formaldehyde	0.23	0.90	3.60
Naphthalene	3.48E-3	1.36E-2	5.43E-2
PAHs(2)	1.38E-3	5.39E-3	2.16E-2
Propylene Oxide	0.10	0.39	1.56
Toluene	0.15	0.58	2.32
Xylene	5.47E-2	0.21	0.85
Total HAPs		2.97	11.9

(1) Not a hazardous air pollutant (HAP) under CAA Section 112.
(2) Polycyclic aromatic hydrocarbons, excluding naphthalene (accounted for separately).

6.2.6.3 Air Quality Impact Analysis

6.2.6.3.1 Air Quality Modeling Methodology

An assessment of impacts on ambient air quality of the proposed facility has been conducted using EPA-approved air quality dispersion models. These models are based on fundamental mathematical descriptions of atmospheric processes in which a pollutant source can be related to a receptor area. The modeling protocol submitted to the District is included as Appendix 6.2-2, Attachment 6.2-2.1.

The impact analysis was used to determine the worst-case ground-level impacts of the Project. The results were compared with established ambient air quality standards and significance levels. If the standards are not violated and significance levels are not exceeded under worst-case conditions, then no exceedances are expected under any conditions. In accordance with regulatory guidance (EPA, 1998; ARB,1989), the ground-level impact analysis includes the following worst-case dispersion conditions:

- impacts in simple terrain,
- impaction of plume on elevated terrain,
- aerodynamic downwash due to nearby building(s),
- impacts from fumigation conditions, and
- impacts from shoreline fumigation conditions.

Simple terrain impacts were assessed for meteorological conditions that would cause the plume to loop, cone, or fan out. Looping plumes occur when the atmosphere is very unstable, such as on a bright sunny afternoon when vigorous convective mixing of the air can transport the entire plume to ground level near the source. Coning plumes occur throughout the day when the atmosphere is neutral or slightly unstable. Fanning plumes are most common at night and in the early morning, when the atmosphere is stable and vertical motions are suppressed.

Plume impaction on elevated terrain, such as on the slope of a nearby hill, can cause high ground-level concentrations, especially under stable atmospheric conditions. High ground-level pollutant concentrations can also be caused by building downwash. Building downwash occurs when a building is in close proximity to the emission stack and results in plume wake around the building; the stack plume is drawn downward to the ground by the lower pressure region that exists in the turbulent wake on the lee side of an adjacent building.

Fumigation conditions occur when a stable layer of air lies a short distance above the release point of the plume and an unstable air layer lies below. The low mixing height that results from this condition allows little diffusion of the stack plume before it is carried downwind to the ground. Although fumigation conditions rarely last as long as an hour, relatively high ground-level concentrations may be reached during that period. Fumigation tends to occur under clear skies and light winds, and is more prevalent in the summer. Because land surfaces tend to both heat and cool more rapidly than water, shoreline fumigation tends to occur on sunny days when the denser cooler air over water displaces the warmer, lighter air over land. During an inland sea breeze, the unstable air over land gradually increases in depth with inland distance. The boundary between the stable air over the water and the unstable air over the land and the wind speed determine if the plume will loop down before much dispersion of the pollutants has occurred.

The basic model equation used in this analysis assumes that the concentrations of emissions within a plume can be characterized by a Gaussian distribution about the centerline of the plume (see Figure 6.2-15). The Gaussian dispersion models approved by EPA for regulatory use are generally conservative (i.e., the models tend to overpredict actual impacts). The EPA models were used to determine if ambient air quality standards may be exceeded, and whether a more accurate and sophisticated modeling procedure would be warranted to make the impact determination. The sections that follow describe:

- Screening procedures;
- Refined air quality impact analysis;
- Existing ambient pollutant concentrations and preconstruction monitoring;
- Results of the ambient air quality modeling analyses; and
- PSD increment consumption.

The screening and refined air quality impact analyses were performed using the latest version of the Industrial Source Complex, Short-Term Model ISCST3 (Version 00101). ISCST3 is a versatile Gaussian dispersion model capable of assessing impacts from a variety of separate sources in regions of simple, intermediate, and complex terrain. The model can account for settling and dry deposition of particulate; area, line, and volume sources; plume rise as a function of downwind distance; separation of point sources; and elevated receptors. The model is capable of estimating concentrations for a wide range of averaging times (from one hour to one year). Impacts in simple terrain under downwash conditions, particularly areas close to the stack where building downwash may occur, were also estimated using the ISCST3 model.

Inputs required by the ISCST3 model include the following:

- Model options;
- Meteorological data;
- Source data; and
- Receptor data.

Model options refer to user selections that account for conditions specific to the area being modeled or to the emissions source that needs to be examined. Examples of model options include use of site-specific vertical profiles of wind speed and temperature; consideration of stack and building wake effects; and time-dependent exponential decay of pollutants. The model supplies recommended default options for the user. Except where explicitly stated, such as for building downwash (described in more detail below), default values were used. A number of these default values are required for EPA and local District approval of model results.

The EPA regulatory default options used include stacktip downwash effects; buoyancy-induced dispersion for heated effluent; and exclusion of calm meteorological conditions (wind speeds of less than one meter per second) from the dispersion calculations.

The performance of ISCST3 is improved by the use of actual meteorological data. The EPA criteria for determining whether the meteorological data are representative are the proximity of the meteorological monitoring site to the area under consideration; the complexity of the terrain; the exposure of the meteorological monitoring site; and the period of time during which the data are collected. The meteorological data set determined to be representative for use for the proposed Project consists of data collected by PG&E at MBPP between 1994 and 1996. These data meet the EPA criteria for representativeness, as follows:

- Proximity: The data were collected on-site, and thus meet the criteria for proximity.
- Complexity of Terrain and Exposure of Meteorological Monitoring Site: The terrain surrounding the meteorological station is the same as the terrain surrounding the Project: fairly flat with small, isolated hills nearby and complex terrain approximately one mile to the east. There are no terrain features that would cause the meteorological data to be affected differently than the Project site, so the exposure of the station and the Project are identical.
- Period of Data Collection: Meteorological data have been collected at the meteorological station for many years. The 1994 through 1996 data set was selected by the SLOCAPCD as representing recent available data and spanning a three–year period to provide exposure to a variety of meteorological conditions. As the data were collected on-site, one year of meteorological data would be sufficient under EPA guidelines.

The required emission source data inputs to ISCST3 include source locations, source elevations, stack heights, stack diameters, stack exit temperatures and velocities, and emission rates. The source locations are specified for a Cartesian (x,y) coordinate system where x and y are distances East and North in meters, respectively. The stack height that can be used in the model is limited by federal Good Engineering Practice (GEP) stack height restrictions, discussed in more detail below. In addition, ISCST3 requires nearby building dimension data to calculate the impacts of building downwash.

The determination of an appropriate height for an exhaust stack is based on a number of factors, including engineering, public health, and aesthetics. The engineering factors ensure that the stack is designed to allow the stack gases to move efficiently. In addition, the stack must be designed so that the air emissions in the exhaust gas can be accurately measured. The height of the stack and the speed and temperature of the exhaust gases determine the shape and dimensions of the exhaust plume under different weather conditions. These engineering factors usually influence the shape, diameter, and height of the stack.

Public health considerations ensure that the stack will not result in unhealthy concentrations of air pollutants under any combination of operating conditions and weather conditions. These factors relate to stack diameter and height.

The aesthetic factors ensure that the stack presents the minimum possible disturbance to viewsheds, and principally relate to stack height.

When all three of these considerations are combined, the stack shape and diameter are established through engineering design parameters and the stack height is set at the lowest height where the engineering and public health criteria are met. The aesthetic considerations are accommodated to the extent possible once compliance with the engineering and public health criteria is achieved. In the case of the new units at the MBPP, the minimum height required to meet all of the engineering criteria was 145 feet. This, then, became the first height evaluated for air quality and public health impacts. The air quality impacts were evaluated for the complete range of turbine operating conditions using three full years of weather data collected at the site. This process ensured that all possible combinations of turbine operating conditions and weather conditions were evaluated. The results of this worst-case analysis were compared with applicable state and federal air quality standards and health risk levels. The analysis showed that the 145-foot stack height would not result in unhealthy air quality impacts; consequently, this stack height was accepted for the Project design.

For the purposes of modeling, a stack height beyond what is required by Good Engineering Practices (GEP) is not allowed (40 CFR 52.21 (h)). However, this requirement does not place a limit on the actual constructed height of a stack. GEP, as used in modeling analyses, is the height necessary to ensure that emissions from the stack do not result in excessive concentrations of any air pollutant in the immediate vicinity of the source as a result of atmospheric downwash, eddies, or wakes that may be created by the source itself, nearby structures, or nearby terrain obstacles. In addition, the GEP modeling restriction assures that any required regulatory control measure is not compromised by the effect of that portion of the stack that exceeds the GEP. The EPA guidance (EPA, 1985) for determining GEP stack height is as follows:

$$H_g = H + 1.5L$$

where

H_g = Good Engineering Practice stack height, measured from the ground-level elevation at the base of the stack

H = height of nearby structure(s) measured from the ground-level elevation at the base of the stack

L = lesser dimension, height or projected width, of nearby structure(s)

In using this equation, the guidance document indicates that both the height and width of the structure are determined from the frontal area of the structure, projected onto a plane perpendicular to the direction of the wind.

For the turbine/HRSG stacks, the nearby (influencing) structures are the HRSGs, which are 90 feet (27.43 meters [m]) high and 198 feet (60.4 m) long. Thus H = L = 90 feet, and H_g = (2.5 * 90 ft) = 225 ft, and the proposed stack height of 145 feet does not exceed GEP stack height.

For the boiler stacks, the nearby structure is the boiler building, which is 153 feet high and has a projected width of 217 feet. For this building, H = L = 153 feet and H_g = 383 feet. Thus the boiler stacks cannot be modeled at their full physical height of 450 feet; the heights are GEP-limited to 383 feet.

For regulatory applications, a building is considered sufficiently close to a stack to cause wake effects when the distance between the stack and the nearest part of the building is less than or equal to five times the lesser of the height or the projected width of the building.

For the buildings analyzed as downwash structures, the building dimensions, accurate to ± 1 foot, were obtained from the facility plot plans. The building dimensions were analyzed using software designed specifically for this purpose (program BEE-BPIP (Building Profile Input Program), Bowman Environmental Engineering, Dallas, TX) to derive 36 wind-direction-specific building heights and projected building widths for use in building wake calculations. The building dimensions used in the GEP analysis are shown in Appendix 6.2-2, Figure 6.2-2.1.

Screening Procedures

To ensure the impacts analyzed were for maximum emission levels and worst-case dispersion conditions, a screening procedure was used to determine the inputs to the impact modeling. The screening procedure analyzed the turbine operating conditions that would result in the maximum impacts on a pollutant-specific basis. The operating conditions examined in this screening analysis, along with their exhaust and emission characteristics, are shown in Appendix 6.2-2, Table 6.2-2.1. These operating conditions represent a range of turbine loads (100% with duct firing, 100% without duct firing, and 50%) at maximum and minimum anticipated operating temperatures (85° and 34°F).

The operating conditions were screened for worst-case ambient impact using EPA's ISCST3 model and the meteorological data described above. The screening analysis showed that maximum ground-level concentrations for all pollutants and averaging periods except annual PM_{10} result during 100% load operation with duct firing at the maximum nominal temperature (85°). Maximum annual PM_{10} impacts are predicted to occur during 50% load operation at maximum nominal temperature. The results of the screening procedure are presented in Appendix 6.2-2, Table 6.2-2.2. The stack parameters for the turbine operating condition that produced the maximum modeled impact for each pollutant and averaging period were then used in the refined modeling analysis to evaluate the modeled impacts of the entire Project for each pollutant and averaging period.

The screening analysis included both simple and complex terrain. Terrain features were taken from USGS DEM data and 7.5-minute quadrangle maps of the area. For the screening analysis, a coarse Cartesian grid of receptors spaced at 180 meters was used with a finer grid, spaced at 25 meters, around the facility fenceline. The coarse grid extended to approximately seven kilometers east of the facility and three kilometers in the other directions to ensure that maximum turbine impacts were identified.

Refined Air Quality Impact Analysis

The complete modeling input for each pollutant and averaging period is shown in Appendix 6.2-2, Tables 6.2-2.3 and 2.4. As discussed above, the turbine stack parameters used in modeling the impacts for each pollutant and averaging period reflected the worst-case turbine operating condition for that pollutant and averaging period identified in the screening analysis. Boiler emissions reflect actual average emission rates during the most recent three-year period.

In evaluating ambient impacts of the Project, the turbines alone were modeled. This results in a conservative, worst-case estimate of Project impacts, as it does not reflect the benefits of eliminating emissions from existing Units 1 through 4.

The model receptor grid was derived from 30 x 30 meter DEM data. Initially, a 180 x 180 meter interval coarse receptor grid was extended in the four cardinal directions from the stack. The Cartesian grid extended seven kilometers to the east of the facility center and three kilometers in the other directions. Receptors were also placed in Cayucos, Los Osos, and Cambria.

Fine receptor grids (60 x 60 meter) were used in areas where the coarse grid analysis indicated modeled maxima would be located. Receptors over the bay and ocean were included in both the coarse and fine grids. A map showing the layout of the modeling grid is presented in Figure 6.2-16.

Receptors for the refined modeling analysis were from USGS DEM data for three 7.5-minute quadrangles (Morro Bay South, Morro Bay North, and Cayucos). The coarse grid contained a total of 2,356 receptors. The refined grids contained a total of 1,203 receptors.

Specialized Modeling Analyses

- **Fumigation Modeling**: Fumigation occurs when a stable layer of air lies a short distance above the release point of a plume and unstable air lies below. Under these conditions, an exhaust plume may be drawn to the ground with little diffusion, causing high ground-level pollutant concentrations. Although fumigation conditions rarely last as long as one hour, relatively high ground-level concentrations may be reached during that time.

  The SCREEN3 model was used to evaluate maximum ground-level concentrations for short-term averaging periods (24 hours or less) under fumigation conditions. EPA guidance (1992) was followed in evaluating fumigation impacts. Emission rates and stack parameters for the refined modeling analysis were used in the fumigation analysis. Since SCREEN3 is a single source model, a single turbine was modeled and the impacts were multiplied by four to determine total impacts under fumigation conditions.

  Calculation of inversion breakup fumigation impacts is shown in Appendix 6.2-2, Table 6.2-2.5.

- **Shoreline Fumigation Modeling**: Shoreline fumigation modeling was also conducted to determine the impacts as a result of overwater plume dispersion. Because land surfaces tend both to heat and to cool more rapidly than water, shoreline fumigation tends to occur on sunny days when the denser cooler air over water displaces the warmer, lighter air over land. During an inland sea breeze, the unstable air over land gradually increases in depth with inland distance. The boundary between the stable air over the water and the unstable air over the land and the wind speed determine if the plume will loop down before much dispersion of the pollutants has occurred.

SCREEN3 can examine sources within 3000 meters of a large body of water, and was used to calculate the maximum shoreline fumigation impact. The model uses a stable onshore flow and a wind speed of 2.5 meters per second; the maximum ground-level shoreline fumigation concentration is assumed by the model to occur where the top of the stable plume intersects the top of the well-mixed thermal inversion boundary layer (TIBL). The model TIBL height was varied in accordance with BAAQMD procedures* (between 2 and 6) to determine the highest shoreline fumigation impact. The worst-case (highest) impact was used in determining facility impacts due to shoreline fumigation. In accordance with EPA guidance, shoreline fumigation was assumed to persist for a maximum of 90 minutes, and the impacts on all short-term averaging periods were assessed.

Calculation of shoreline fumigation impacts is also shown in Appendix 6.2-2, Table 6.2-2.5.

- **Turbine Startup**: Facility impacts were also modeled during the startup of two turbines to evaluate short-term impacts under startup conditions. This analysis included two turbines in startup and two turbines at maximum load with duct firing. Emission rates during startup were based on an engineering analysis of available data, which included source test data from startups of the GE gas turbine at the Crockett Cogeneration Project. A summary of the data evaluated in developing these emission rates was shown in Appendix 6.2-1, Table 6.2-1.4. The hourly startup emission rates shown for NOx and CO are hourly average values over the startup period. Maximum hourly emissions during a single hour are expected to be no higher than 1.5 times the average hourly startup emissions, and these maximum hourly rates were used in evaluating startup impacts.

  Turbine exhaust parameters for the minimum operating load point (50%) were used to characterize turbine exhaust during startup. Startup impacts were evaluated for both the one- and three-hour averaging periods using ISCST3**. Emission rates and stack parameters used in the startup modeling analysis are shown in Table 6.2-34 below. Calculation of startup impacts is shown in more detail in Appendix 6.2-2, Table 6.2-2.6.

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* BAAQMD procedures implement the EPA guidance on evaluating shoreline fumigation (EPA 1992).

** The ISC_OLM version of the ISCST3 model was used with concurrent ozone data from the District's Morro Bay monitoring station to determine hourly NO_2 impacts under startup and commissioning conditions.

TABLE 6.2-34
EMISSION RATES AND STACK PARAMETERS USED IN MODELING ANALYSIS FOR TURBINE STARTUP EMISSIONS IMPACTS

PARAMETER	UNITS	STARTUP	BASE LOAD WITH DUCT FIRING
Turbine stack temperature	degrees K	344.1	353.6
Turbine exhaust velocity	meters per second	12.13	18.41
One-hour average impacts			
NOx emission rate	pounds per hour	120	18.75
SO_2 emission rate	pounds per hour	0.77	1.45
CO emission rate	pounds per hour	1240	27.41
Three-hour average impacts			
NOx emission rate	--	--	--
SO_2 emission rate	pounds per hour	0.77	1.45
CO emission rate	--	--	--

- **Turbine Commissioning:** Two high-emissions scenarios are possible during commissioning. The first would be the period of time prior to SCR system installation when the combustor is being tuned. Under this scenario, NOx emissions would be high because the NOx emissions control system would not be functioning and because the combustor would not be tuned for optimum performance. CO emissions would also be high because combustor performance would not be optimized; however, since there is no external CO control for the turbines, CO emissions during commissioning are not expected to be any higher than CO emissions evaluated during startup operations.

  The second high-emissions scenario would occur when the combustor has been tuned but the SCR installation is not complete, and other parts of the turbine operating system are being checked out. This is likely to occur under transient conditions, characterized by 50 percent load operation. Since the combustor would be tuned but the SCR installation would not be complete, CO levels would not be expected to be elevated but NOx levels would again be high. Therefore, this analysis will be limited to ambient NO_2 impacts during commissioning.

- **Fog Effects on Dispersion:** Fog is the result of specific meteorological conditions (very high relative humidity, often accompanied by low wind speeds) that generally occur in the lower atmosphere. The conditions that produce fog are contained within the meteorological data that were collected near the power plant. Dispersion during foggy conditions was evaluated by isolating these meteorological conditions in the three-year meteorological data set and comparing modeled short-term impacts under these conditions with the maximum modeled impacts under all meteorological conditions.

6.2.6.3.2 Results of the Ambient Air Quality Modeling Analyses

Maximum baseline and future facility impacts are summarized in Tables 6.2-35 and 6.2-36, respectively. The analysis shows that the maximum impacts from the existing boilers and the new turbines occur on Morro Rock. Shoreline fumigation dispersion conditions produce the maximum short-term turbine impacts.

TABLE 6.2-35
SUMMARY OF RESULTS FROM REFINED MODELING ANALYSES: EXISTING BOILERS
MORRO BAY POWER PLANT

POLLUTANT	AVERAGING TIME	MODELED CONCENTRATIONS ($\mu g/m^3$)	
		High	Highest Second High[2]
NOx[1]	1-hour	222.7	n/a
	Annual	2.0	n/a
SO_2	1-hour	3.22	n/a
	3-hour	n/a	2.31
	24-hour	0.90	0.61
	Annual	0.03	n/a
CO	1-hour	416.2	408.2
	8-hour	224.4	184.1
PM_{10}	24-hour	11.4	7.82
	Annual	0.33	n/a

(1) Modeled using ISC_OLM with concurrent ozone data to account for ozone limiting of NOx formation.
(2) H2H concentrations used for comparison with short-term federal standards.

Impacts During Turbine Commissioning

As discussed above, there are two potential scenarios during turbine commissioning activities under which NO_2 impacts could be higher than under other operating conditions already evaluated.

Scenario 1: Under this scenario, NOx emissions can be conservatively estimated to be twice the guaranteed turbine-out level of 25 ppmvd @ 15 percent O_2, or 50 ppm. If operation under this condition were to continue for 1 hour, maximum hourly NOx emissions at full load would be (50 ppm / 2.5 ppm) * 16.72 lbs/hr = 334.4 lbs/hr.

TABLE 6.2-36
SUMMARY OF RESULTS FROM REFINED MODELING ANALYSES: TURBINES
MORRO BAY POWER PLANT

POLLUTANT	AVG TIME	MODELED CONCENTRATIONS ($\mu g/m^3$)				
		ISCST3		FUMIGATION	SHORELINE FUMIGATION	STARTUP
		High	Highest Second High			
NOx[1]	1-hour Annual	220.4 2.6	n/a n/a	13.3 --	105.1 --	185.9 --
SO_2	1-hour 3-hour 24-hour Annual	17.3 11.9 2.7 0.23	n/a 10.4 2.2 n/a	1.03 0.93 0.41 --	8.1 4.1 0.54 --	11.9 8.3 -- --
CO	1-hour 8-hour	326.3 1,508.3	317.0 1,249.6	19.5 159.3	153.6 347.7	8,615.4 --
PM_{10}	24-hour Annual	24.2 2.7	20.2 n/a	3.6 --	4.6 --	-- --

(1) Modeled using ISC_OLM with concurrent ozone data to account for ozone limiting of NO_2 formation.
(2) H2H concentrations used for comparison with short-term federal standards

__Scenario 2__: Under these lower load conditions, NOx emissions could be as high as 100 ppm @ 15 percent O_2. Based on the transient nature of the loads, the average fuel consumption would be expected to be equivalent to half the full load flow rate, or 925 MMBtu/hr. Worst-case hourly NOx emissions under this scenario would be (100 ppm/2.5 ppm) * 8.36 lbs/hr = 334.4 lbs/hr.

As the maximum hourly emissions under each scenario are expected to be the same, the maximum modeled NO_2 impact will occur under the turbine operating conditions that are less favorable for dispersion. These conditions are expected to occur at 50 percent load, because exhaust mass flow and thus final plume rise are lower than at full load.

The results of the turbine screening analysis can be used to evaluate modeled NOx impacts of a single turbine at this emission rate. The screening analysis showed that the highest one-hour unit impact is 27.17 $\mu g/m^3$ per g/s. Using the 334.4 lb/hr (42.13 g/s) emission rate derived above yields a maximum one-hour NOx impact under either scenario of 1,144.8 $\mu g/m^3$ __before__ ozone limiting. With ozone limiting, the highest one-hour NO_2 concentration during commissioning is not expected to exceed 210.8 $\mu g/m^3$. Using the background NO_2 concentration of 122 $\mu g/m^3$, the total impact will not exceed 332.8 $\mu g/m^3$, which is well below the state one-hour NO_2 standard of 470 $\mu g/m^3$.

Fog Effects on Dispersion

In the 1994 meteorological data set, about 29% of all hours were identified as having meteorological conditions that would be expected to produce fog, based on a relative humidity in excess of 91.7 %. This criterion yields 51% of all days at Morro Bay in 1994 having at least one hour of fog, which corresponds to the long-term fog statistics shown by the National Weather Service at the Point Mugu station. Emissions from the existing boilers and the new turbines were modeled separately using ISCST3 and these meteorological conditions to evaluate ambient impacts of the existing and proposed power plants under foggy conditions. The modeling results show that the weather conditions that cause fog can also affect dispersion, mostly depending on the mixing height and the persistence of the wind direction. Fog by itself only indirectly affects dispersion, usually through its influence on establishing mixing height. Maximum impacts are lower on Morro Rock when it is foggy, because mixing heights are usually higher than when there is no fog. However, impacts on other hills to the north-northeast, east-northeast and southeast of the power plant are higher when it is foggy because the prevailing winds appear to be more persistent than when there is no fog. Since the foggy and non-foggy conditions alike are included in the three-year meteorological data set used to model impacts for the project, the effects of fog on dispersion are reflected in the results reported in Table 6.2-36.

Ambient Air Quality Impacts

To determine the maximum ground-level impacts on ambient air quality for comparison to the applicable standards, modeled worst-case impacts (shown in Table 6.2-36) were added to maximum observed background concentrations.

For background ambient pollutant concentrations for those pollutants that do not exceed the PSD monitoring exemption levels (see below), EPA guidelines (Section 2.4, EPA, 1987) state that the existing monitoring data must be representative of the proposed facility impact area. ARB monitors ambient NO_2 and CO concentrations in San Luis Obispo, less than 20 miles from MBPP. This monitoring station is situated in a more developed area than the power plant, and concentrations monitored there are expected to be somewhat higher than those at Morro Bay. SO_2 is monitored in Grover City, approximately 20 miles southeast of Morro Bay; SO_2 monitoring at Morro Bay ended after 1995. During the period when SO_2 concentrations were monitored in both locations, Grover City concentrations were consistently higher than those measured in Morro Bay. Therefore, the most recent concentrations monitored in Grover City provide a conservatively high background concentration for SO_2 at Morro Bay. ARB also monitors PM_{10} at Morro Bay. The most recent three years (Section 2.4.3 of EPA guidelines, 1987) of the existing monitoring data are used for background ambient pollutant concentrations.

Table 6.2-37 presents the maximum concentrations of NOx, SO_2, CO, and PM_{10} recorded for 1996 through 1998 from the San Luis Obispo, Grover City, and Morro Bay monitoring stations.

Maximum ground-level impacts due to operation of the facility are shown together with the ambient air quality standards in Table 6.2-38. Despite the conservative (overpredictive) assumptions used throughout the analysis, the results indicate that the addition of the new turbines at MBPP will not cause or contribute to violations of any state or federal air quality standards, with the exception of the state PM_{10} standard. For this pollutant, existing concentrations already exceed the state standard; however, as discussed further below, the proposed Project will result in a cumulative impact that is below PSD significance levels. In addition, offsets will be provided for the net increase in PM_{10} emissions from the Project; this is also discussed further below.

TABLE 6.2-37
MAXIMUM BACKGROUND CONCENTRATIONS, 1997-1999 ($\mu g/m^3$)

POLLUTANT	AVERAGING TIME	1997	1998	1999
San Luis Obispo Monitoring Station				
NO_2	1-Hour Annual	122 25	115 23	120 25
CO	1-Hour 8-Hour	6,988 3,028	4,571 2,555	5,714 3,444
Grover City Monitoring Station				
SO_2	1-Hour 24-hour Annual	106 8 0	47 10 0	104 13 0
Morro Bay Monitoring Station				
PM_{10}	24-Hour Annual (AAM)[1] Annual (AGM)[2]	57 20.6 18.6	33 13.5 14.6	39 14.4 15.7

(1) Annual Arithmetic Mean
(2) Annual Geometric Mean

TABLE 6.2-38
MODELED MAXIMUM PROJECT IMPACTS: NEW TURBINES ONLY
INCLUDING IMPACTS ON MORRO ROCK
MORRO BAY POWER PLANT

POLLUTANT	AVG TIME	PROJECT IMPACT (μg/m³) High	PROJECT IMPACT (μg/m³) Highest Second High	BACK-GROUND (μg/m³)	TOTAL IMPACT (High) (μg/m³)	STATE STD (μg/m³)	TOTAL IMPACT (H2H) (μg/m³)	FEDERAL STD (μg/m³)
NO_2	1-hour	220.4	--	122	342.4	470	--	--
	Annual	2.6	--	25	--	--	27.6	100
SO_2	1-hour	17.3	--	106	123.3	650	--	--
	24-hour	11.9	10.4	13	24.9	109	23.4	365
	Annual	0.23	--	0	0.23	--	0.23	80
CO	1-hour	8,615.4	--	6,988	15,603	23,000	15,603	40,000
	8-hour	1,508.3	1,249.6	3,444	4,952	10,000	4,694	10,000
PM_{10}	24-hour	24.2	20.2	57	81.2	50	77.2	150
	Annual(1)	2.7	--	20.6	23.3	30	--	--
	Annual(2)	2.7	--	18.6	--	--	21.3	50

(1) Annual Arithmetic Mean.
(2) Annual Geometric Mean.

Ambient Air Quality Impacts in Other Locations

To provide a more complete assessment of the ambient impacts of the Project on the community, impacts were also evaluated in the nearby towns of Cambria, Cayucos and Los Osos. Table 6.2-39 shows that Project impacts in those communities will be much lower than the maximum concentrations shown in Table 6.2-38.

TABLE 6.2-39
MAXIMUM MODELED CONCENTRATIONS IN NEARBY COMMUNITIES
MORRO BAY POWER PLANT

Pollutant	Averaging Period	Maximum Modeled Concentration from ISCST3, ug/m³: Morro Bay	Cambria	Cayucos	Los Osos
NO_2	1-hour	220	7.6	10.9	10.9
	annual	2.9	0.09	0.10	0.08
SOx	1-hour	17.3	0.6	0.8	0.8
	3-hour	11.9	0.4	0.5	0.5
	24-hour	2.7	0.08	0.2	0.1
	annual	0.23	0.007	0.008	0.006
CO	1-hour	326.3	11.1	15.9	16.0
	8-hour	1,508.3	38.0	55.1	69.6
PM_{10}	24-hour	24.2	0.7	1.5	1.0
	annual	2.7	0.07	0.1	0.07

6.2.6.3.3 PSD Requirements

Applicability of PSD Requirements

Because the Project is considered a major modification to a major stationary source, compliance with PSD requirements must be demonstrated. The PSD program was established to allow emission increases (increments of consumption) that do not result in significant deterioration of ambient air quality in areas where criteria pollutants have not exceeded NAAQS. For the purposes of determining compliance with the requirements of the PSD program, the following regulatory procedure is used.

- Facility emissions are evaluated to determine if the magnitude of emissions may cause significant ambient air quality impacts. Because this facility is a modification to an existing major facility, the level of emissions that requires an analysis of ambient impacts is determined on a pollutant-specific basis.

- If an ambient air quality impact analysis is required, the analysis is first used to determine if the impact levels are significant. The determination of significance is based on whether the ambient impacts exceed established significance levels (40 CFR 51.165(b)(2)). If the significance levels are not exceeded, no further analysis is required. However, for CEQA purposes, a full analysis is required regardless of the modeled impacts.

- If the significance levels are exceeded, an analysis is required to demonstrate that the allowable increments will not be exceeded on a pollutant-specific basis. Increments are the maximum increases in concentration that are allowed to occur above the baseline concentration.

The net increase in facility emissions from Table 6.2-30 is compared with the PSD thresholds for major modifications in Table 6.2-40. This comparison shows that the Project will result in a significant increase only for PM_{10} emissions. The Project will result in net reductions in NOx, VOC, and CO emissions. The increase in emissions of SO_2 from the facility will be below the 40 ton per year threshold, so will not be significant. Thus, the Project is subject to PSD requirements only for PM_{10}.

TABLE 6.2-40
COMPARISON OF EMISSIONS INCREASE WITH FEDERAL PSD SIGNIFICANT EMISSIONS LEVELS MORRO BAY POWER PLANT

POLLUTANT	NET INCREASE (REDUCTION) (tons per year)	PSD SIGNIFICANT EMISSION LEVELS (tons per year)	FURTHER ANALYSIS REQUIRED?
NOx	(563.0)	40	NO
SO_2	13.0	40	NO
VOC	(14.5)	40	NO
CO	(518.7)	100	NO
PM_{10}	76.0	15	YES

Preconstruction Monitoring

To ensure that the impacts from the facility will not cause or contribute to a violation of an ambient air quality standard or an exceedance of a PSD increment, an analysis of the existing air quality in the area of the facility is necessary. The federal PSD regulation requires preconstruction ambient air quality monitoring data for the purposes of establishing background pollutant concentrations in the impact area (40 CFR 52.21 (m)(iii)) of any pollutant for which the project is subject to PSD review. However, a project may be exempted from this requirement if the predicted air quality impacts of the net emissions increase from the proposed modification do not exceed *de minimis* levels.

A facility may, with EPA's approval, rely on air quality monitoring data collected at nearby, representative monitoring stations to satisfy the requirement for preconstruction monitoring. In such a case, in accordance with Section 2.4 of the EPA PSD guideline, the last three years of ambient monitoring data may be used if they are representative of air quality in the location of the maximum concentration increase from the proposed source.

Maximum modeled PM_{10} impacts from the turbines alone are compared with federal PSD *de minimis* levels in Table 6.2-41. Maximum impacts exceed *de minimis* levels.

TABLE 6.2-41
COMPARISON OF MODELED CONCENTRATIONS (TURBINES ALONE) WITH FEDERAL PSD PRECONSTRUCTION MONITORING THRESHOLDS

POLLUTANT	AVERAGING TIME	EXEMPTION CONCENTRATION ($\mu g/m^3$)	MAXIMUM MODELED CONCENTRATION[1] ($\mu g/m^3$)
PM_{10}	24 hours	10	20.2

(1) Highest second-high concentration used for comparison with federal requirements.

In general, the preconstruction monitoring threshold is exceeded only on Morro Rock. Maximum modeled concentrations of PM_{10} are below the threshold in all other locations (see Table 6.2-44, below). In addition, a modeling analysis of impacts from the existing boilers at MBPP shows a 24-hour average PM_{10} concentration from those boilers of slightly over 11 ug/m^3. Because the existing boilers are being shut down as part of this Project, the overall Project impact is significantly less than the modeled concentration of 20.2 ug/m^3. The wind roses presented in Figures 6.2-5a through 6.2-7e of the application show that prevailing winds in the Project area are onshore winds, so existing concentrations of all pollutants on the rock, which is upwind of the City of Morro Bay and other inland urban areas, can be expected to be much lower than concentrations monitored in other locations.

The applicant believes that ambient monitoring data exist that are representative of existing air quality in the Project area so that additional preconstruction monitoring is not necessary. All of the background ambient air quality data used in this analysis were collected in accordance with ARB guidance and reflect concentrations monitored within the past three years; thus, the data meet the EPA criteria for data quality and currentness.

To represent existing PM_{10} concentrations, the applicant proposes to use ambient PM_{10} monitoring data collected at the Morro Bay monitoring station, approximately one mile east-southeast of the power plant (see Figure 6.2-17 for locations of plant and monitoring station). Based on the predominant onshore winds, this monitoring station is downwind of the power plant most of the time, so concentrations measured at the station would be expected to represent existing emissions from the power plant as well as PM_{10} emissions from other sources in the City of Morro Bay. The PM_{10} data presented in Table 6.2-37 show that PM_{10} levels in Morro Bay are generally low: approximately 1/3 of the federal standard. By using the 1997 monitored maximum value of 57 ug/m3 (by far the highest concentration monitored in Morro Bay over the past four years), the applicant believes that the background concentrations of PM_{10} in the vicinity of the Project are being conservatively overestimated.

Further, a comparison of the 1997, 1998, and 1999 monitored PM_{10} concentrations in other nearby locations indicates that PM_{10} concentrations in the region remain well below the federal standard. This comparison is shown in Table 6.2-42 below. Therefore, the addition of the Project would not be expected to bring ambient PM_{10} levels anywhere near the national ambient air quality standard.

TABLE 6.2-42
MONITORED 24-HOUR AVERAGE PM_{10} CONCENTRATIONS IN THE VICINITY OF MORRO BAY POWER PLANT

Monitoring Station	Calendar Year			Distance/Direction from Morro Bay Power Plant (mi)
	1997	1998	1999	
Morro Bay	57	33	39	~1 (ESE)
San Luis Obispo	55	32	44	~13 (SE)
Atascadero	70	47	43	~13 (NE)

Assessment of Significance for PSD

The maximum modeled PM_{10} impacts due to the Project are compared with the federal PSD significance levels in Table 6.2-43 below. Again, because the net increases of emissions of all pollutants except PM_{10} are below the PSD significant emissions thresholds, this analysis is not required under PSD for the other criteria pollutants.

TABLE 6.2-43
MAXIMUM MODELED IMPACTS AND FEDERAL PSD SIGNIFICANCE THRESHOLDS MORRO BAY POWER PLANT

POLLUTANT	AVERAGING TIME	MODELED IMPACTS[1] ($\mu g/m^3$)	FEDERAL PSD SIGNIFICANCE THRESHOLD ($\mu g/m^3$)	SIGNIFICANT UNDER FEDERAL PSD?
PM_{10}	24 hours	20.2	5	YES
	annual	2.7	1	YES

(1) Highest second high used for 24-hour averaging period, highest modeled concentration used for annual averaging period.

This comparison shows that ambient impacts of PM_{10} from the Project are significant for PSD.

Assessment of Significance for CEQA

One commonly used measure of the significance of ambient Project impacts is the PSD significance levels. The maximum modeled impacts from the facility are compared with these significance levels in Table 6.2-44 below. This comparison shows that the significance levels for air quality impacts in Class II areas are exceeded for NOx, SO_2, one-hour CO, and annual PM_{10} only on Morro Rock. The significance level for 8-hour CO and 24-hour PM_{10} is exceeded in other locations as well. Although public access to Morro Rock is prohibited, the state park signage does not prevent physical access to the rock; therefore, under federal regulations, the rock is considered ambient air. However, since the rock is not legally accessible to the public, impacts there do not need to be evaluated for CEQA purposes. Since modeled impacts of all pollutants other than CO and PM_{10} at all other locations are well below the significance levels, under CEQA, most ambient impacts of the Project do not exceed the federal significance thresholds.

TABLE 6.2-44
COMPARISON OF MODELED IMPACTS FROM ISCST3 AND PSD SIGNIFICANCE THRESHOLDS MORRO BAY POWER PLANT[1]

POLLUTANT	AVERAGING TIME	MAXIMUM MODELED IMPACTS FROM ISCST3, µg/m³		FEDERAL PSD SIGNIFICANCE THRESHOLD, µg/m³	SIGNIFICANT UNDER FEDERAL PSD?	
		ALL LOCATIONS	EXCLUDING MORRO ROCK		ALL LOCATIONS	EXCLUDING MORRO ROCK
NO_2	Annual	2.9	0.9	1.0	YES	NO
SO_2	3-Hour	10.4	3.8	25	NO	NO
	24-Hour	2.2	0.97	5	NO	NO
	Annual	0.2	0.1	1.0	NO	NO
PM_{10}	24-Hour	20.2	8.7	5	YES	YES
	Annual	2.7	0.8	1.0	YES	NO
CO	1-Hour	317.0	121.6	2,000	NO	NO
	8-Hour	1,249.6	528.1	500	YES	YES

(1) Highest second high used for short-term averaging periods, highest modeled concentration used for annual averaging period.

This modeling analysis does not account for the reductions in ambient concentrations that will occur from the shutdown of existing Units 1 through 4 at MBPP, or for the ambient reductions that will occur from the additional PM_{10} and PM_{10} precursor offsets that will be provided. The applicant believes that these CO and PM_{10} reductions will mitigate the impact of CO and PM_{10} emissions from the Project.

PSD Increment Consumption

Since the Project net emissions increases of NOx, CO, and SO_2 do not exceed PSD significance levels, an increments analysis is required only for PM_{10}. According to EPA Region IX staff, it has been determined that the application for a PSD permit for the proposed modification will be the first PSD application filed in San Luis Obispo County since the PSD trigger dates. Further, based on consultations with Monterey Bay Unified APCD, Santa Barbara County APCD, and San Joaquin Valley Unified APCD staffs, no PSD permits have been issued in those districts since the trigger date for sources that would have an annual average impact greater than 1 $\mu g/m^3$ in San Luis Obispo County. Therefore, the proposed Project would set the baseline date and is the only increment-consuming source in the District. Compliance with the PM_{10} increments is demonstrated by comparing the ambient impacts of the Project with the Class II increments for PM_{10}. This comparison is shown in Table 6.2-45 below.

TABLE 6.2-45
COMPARISON OF MAXIMUM MODELED IMPACTS FROM ISCST3
AND PSD CLASS II PM_{10} INCREMENTS
MORRO BAY POWER PLANT[1]

AVERAGING TIME	MAXIMUM MODELED IMPACT, µg/m³	PSD CLASS II INCREMENT, µg/m³	IN COMPLIANCE WITH INCREMENT?
24 hours	20.2	30	YES
annual	2.7	17	YES

(1) Based on regulatory guidance, highest second high used for 24-hour averaging period; highest modeled concentration used for annual averaging period.

Ambient Air Quality Impacts

Under the PSD regulations, the applicant must also make a demonstration that the Project will not cause or contribute to a violation of NAAQS. This demonstration was made previously in Table 6.2-40.

Impacts in Class I Areas

Federal regulations limit the degradation of air quality in areas designated Class I by imposing more stringent limits on air quality impacts there from new sources and modifications.* The only area designated Class I by EPA within 100 km of the Project is the San Rafael Wilderness in the Los Padres National Forest. Receptors were placed along the boundary of the Class I area nearest the Project to evaluate the maximum modeled impacts of the Project on the area. Since the Project is significant only for CO and PM_{10}, only CO and PM_{10} impacts are required to be modeled. However, for this analysis, all pollutants were included.

The results of the modeling analysis are compared with the Class I increments in Table 6.2-46. These results show that the modeled impacts of the Project in the nearby Class I area are far below the PSD Class I increments and will not significantly degrade air quality.

* Class I areas are areas designated by EPA as requiring special protection, such as National Parks and National Forests.

TABLE 6.2-46
PROJECT IMPACTS IN CLASS I AREA
MORRO BAY POWER PLANT[1]

POLLUTANT	AVERAGING PERIOD	IMPACT IN SAN RAFAEL WILDERNESS ($\mu g/m^3$)	PSD CLASS I INCREMENT ($\mu g/m^3$)
NO_2	Annual	0.01	2.5
SO_2	Annual 24 hours 3 hours	0.0009 0.005 0.01	2 5 25
PM_{10}	Annual 24 hours	0.009 0.04	2.8 5.7

(1) Based on regulatory guidance, highest second high used for 24-hour averaging period; highest modeled concentration used for annual averaging period.

6.2.6.4Effects of Noncriteria Pollutants

6.2.6.4.1. Screening Health Risk Assessment

The health risk assessment (HRA) conducted determined the expected impact of potentially toxic compound emissions. The HRA was conducted in accordance with CAPCOA (1993). The acute and chronic hazard indices and carcinogenic risk were calculated using the most recent OEHHA RELs and cancer unit risk factors. Inhalation cancer risk was adjusted for multipathway exposure using multipathway adjustment factors developed by the South Coast AQMD for risk assessments (SCAQMD 1998). The HRA estimated the offsite carcinogenic risk to the maximally exposed individual (MEI), as well as indicated any adverse effects of non-carcinogenic compound emissions. Because of the conservatism (overprediction) built into the established risk analysis methodology, the actual risks will be lower than those estimated.

An HRA requires the following information:

- Unit risk factors (or carcinogenic potency values) for carcinogenic compounds that may be emitted;
- Noncancer Reference Exposure levels (RELs) for determining noncarcinogenic health impacts;
- One-hour and annual average emission rates for each compound of concern; and
- The maximum ambient one-hour and annual average concentration of each compound offsite and at the location of each sensitive receptor.

The unit risk factor of a carcinogenic substance is the estimated probability of a person contracting cancer as a result of constant exposure to an ambient concentration of 1 $\mu g/m^3$ over a 70-year lifetime. This factor represents the theoretical probability of extra cancer occurring in the exposed population assuming a 70-year lifetime exposure. The carcinogenic risk for each pollutant emitted is the product of the unit risk factor and the modeled ambient concentration, adjusted as necessary to reflect multipathway exposure. The carcinogenic risks from individual noncriteria pollutants are assumed to be additive, and the total risk must be below 10 in one million.

An evaluation of the potential noncancer health effects from long-term (chronic) and short-term (acute) exposures has also been included in the HRA. Many of the carcinogenic compounds also cause noncancer health effects and are therefore included in the determination of both cancer and noncancer effects. RELs are used as indicators of potential adverse health effects. These exposure levels are generally based on the most sensitive adverse health effect reported and are designed to protect the most sensitive individuals. Section 6.16 (Public Health) discusses the significance criteria for both carcinogenic and noncarcinogenic health effects in detail.

The noncriteria pollutants listed in Tables 6.2-32 and 6.2-33 were assessed for their health risks at offsite receptors, including the sensitive receptors identified in Table 6.16-1 and Figure 6.16-2.

The HRA results for the Project are presented in Table 6.2-47, and the detailed calculations are provided in Appendix 6.2-3.

The HRA results indicate that noncriteria pollutant impacts from the Project will be well below levels of significant risk. The results also indicate that no sensitive receptors will be adversely affected.

TABLE 6.2-47
HEALTH RISK ASSESSMENT RESULTS
MORRO BAY POWER PLANT

	BASELINE	PROJECT	SIGNIFICANCE LEVEL
Cancer Risk to Maximally Exposed Individual (All Sources)	1.4 in one million	2.5 in one million	10 in one million
Cancer Risk to Maximally Exposed Individual (excluding Emergency Diesel Engines)	<0.01 in one million	1.1 in one million	10 in one million
Acute Noncancer Hazard Index	0.06	0.4	1.0
Chronic Noncancer Hazard Index	0.002	0.009	1.0

6.2.6.4.2 SLOCAPCD Rule 219

SLOCAPCD Rule 219 (Toxics New Source Review) provides a mechanism for evaluating potential impacts of air emissions of toxic substances from new and modified sources. The rule applies only when there is an increase in toxic emissions or the distance to the nearest receptor has decreased. The Project will not affect the operation of the existing Diesel fire pump engines, Diesel emergency generator, or gasoline storage and dispensing, so those sources are not included in the assessment for purposes of this rule.

Although the shutdown of the existing boilers will eliminate emissions of benzene and formaldehyde from those sources, the new turbines will have slightly higher emissions of benzene and formaldehyde and will also emit other noncriteria pollutants that have not been attributed to the boilers in previous health risk assessments. Therefore, the assessment for purposes of compliance with Rule 219 evaluates potential toxic impacts of the proposed new turbines.

The noncriteria pollutant emissions from the new turbines are shown in Table 6.2-33. Only residential receptors were included in this analysis.

Acute and chronic chronic health hazard and cancer risk were assessed using the most recent OEHHA RELs and unit risk factors. Inhalation cancer risk was adjusted for multipathway exposure using multipathway adjustment factors developed by the South Coast AQMD for risk assessments (SCAQMD 1998). The results of this assessment are summarized in Table 6.2-48 below. Health hazard index and cancer risk calculations and a more detailed discussion of the Rule 219 risk assessment are included in Appendix 6.2-4.

TABLE 6.2-48
SLOCAPCD RULE 219 RISK ASSESSMENT RESULTS
MORRO BAY POWER PLANT

	PROJECT	SIGNIFICANCE LEVEL
Cancer Risk to Nearest Resident	0.1 in one million	1 in one million
Acute Noncancer Hazard Index	0.08	0.1
Chronic Noncancer Hazard Index	0.001	0.1

6.2.6.5 Visibility Screening Analysis

The ISCST3 model was used in screening mode to evaluate potential visibility impacts of the Project in the San Rafael Wilderness. The modeling followed screening guidance provided by the Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2

Summary Report, and by Trent Proctor and Mike McCorison of the U.S. Forest Service (USFS) (Federal Land Manager [FLM]).

ISCST3 was used with one year of hourly meteorological data from Morro Bay. In accordance with FLM guidance, flat terrain was assumed. Receptors were placed along the boundary of the Class I area closest to the Project site. Based on FLM Guidance, the VISCREEN model was not used to assess coherent plume visibility impacts because the distance to the Class I area is greater than 50 kilometers.

To assess visibility impacts at the Class I area, the 90th percentile background standard visual range (SVR) of 236 kilometers was used, as recommended by Trent Proctor and Mike McCorison of the USFS. This visual range corresponds to a background extinction coefficient of 16.57 Mm^{-1} (inverse Megameters). The relative humidity correction factor (f(RH)) was 1.99 for the Class I area. The allowable level of acceptable change (LAC) to extinction is 5 percent for USFS Class I areas.

Emission Rates

As discussed earlier, there will be a net reduction in emissions of most pollutants as a result of the Project. Turbine emissions used in the ISCST3 modeling analysis of visibility impacts were identical to those used in modeling the other impacts from the Project (see Appendix 6.2-2, Table 6.2-2.4); however, emission reductions were not modeled. The visibility impact analysis assumes that particulate nitrate (NO_3) is in the form of ammonium nitrate (NH_4NO_3) and that particulate sulfate (SO_4) is in the form of ammonium sulfate ($(NH_4)_2SO_4$). The visibility calculation is based on the resulting ambient concentrations of NH_4NO_3, $(NH_4)_2SO_4$, and PM_{10}, along with representative relative humidity adjustment factors.

Impacts

The maximum 24-hour visibility impact was generated by taking the maximum 24-hour average value at each receptor, regardless of which season it occurred, and assigning it to represent the visibility impact at the San Rafael Wilderness. A 40 percent nitrate conversion rate was assumed to persist for all seasons.

To calculate extinction coefficients, the following general equation is used:

$$b_{ext} = b_{SN} * f(RH) + b_{dry}$$

where:

b_{ext} = particle scattering coefficient

$b_{SN} = 3[((NH_4)_2SO_4) + (NH_4NO_3)]$

$b_{dry} = b_{Coarse}$

The quantities in brackets are the masses expressed in ug/m^3 and can be broken down further into the following equations:

$$b_{NO3} = 3[1.29(NO_3)f(RH)]$$
$$b_{SO4} = 3[1.375(SO_4)f(RH)]$$
$$b_{Coarse} = 0.6[PM_{10}]$$

The 24-hour average concentration data are summarized in Table 6.2-49.

TABLE 6.2-49
MAXIMUM PREDICTED 24-HOUR AVERAGE CONCENTRATIONS FROM ISCST3
MORRO BAY POWER PLANT

CLASS I AREA	NO_3 (ug/m^3)	SO_4 (ug/m^3)	PM_{10} (ug/m^3)
San Rafael Wilderness	0.0727	0.0086	0.0774

The above equations are used to calculate the extinction coefficients and to correct for f(RH) = 1.99 (except for b_{Coarse}, which is not corrected). Table 6.2-50 summarizes maximum extinction coefficients for each pollutant and total extinction.

TABLE 6.2-50
MAXIMUM IMPACTS ON VISIBILITY IN PROTECTED AREA
MORRO BAY POWER PLANT

CLASS I AREA	b_{NO3} (Mm-1)	b_{SO4} (Mm-1)	b_{Coarse} (Mm-1)	24-HOUR AVERAGE VISIBILITY IMPACT (Mm-1)	PERCENT CHANGE IN EXTINCTION	ACCEPTABLE CHANGE
San Rafael Wilderness	0.5599	0.0706	0.0464	0.6769	4.07	5

This calculation yields a change in extinction for the San Rafael Wilderness of 4.07 percent, which is less than the level of acceptable change of 5 percent for the Class I area.

6.2.6.6 Construction and Demolition Impacts Analysis

Analysis of the potential ambient impacts from air pollutants during the construction of the new turbines and the demolition of the existing boilers and stacks includes an assessment of emissions from vehicle and equipment exhaust and the fugitive dust generated from material handling. A detailed analysis of the emissions and ambient impacts is included in Appendix 6.2-5. With the exception of the maximum modeled 24-hour and annual average PM_{10} concentrations, the results of the analysis indicate that the maximum construction and demolition impacts will be below the state and federal standards for all the criteria pollutants emitted. The best available emission control techniques will be used for dust suppression and engine emissions during construction and demolition.

The MBPP construction site impacts are not unusual in comparison to most construction sites; construction sites that use good dust suppression techniques and low-emitting vehicles typically do not cause violations of air quality standards. The ISCST3 model overpredicts PM_{10} construction emission impacts due to the cold plume (i.e., ambient temperature) effect of dust emissions. Therefore it is unlikely that the construction activities will cause any violations of the PM_{10} standards.

Potential carcinogenic risks due to the brief exposure to Diesel exhaust during construction and demolition operations were also assessed. This analysis shows that the carcinogenic risk due to this exposure is expected to be well below the 10 in one million level considered to be significant.

6.2.7 CONSISTENCY WITH REGULATORY REQUIREMENTS

6.2.7.1 Consistency with Federal Requirements

As discussed in Section 6.2.3, EPA has retained the authority to issue PSD permits for projects in San Luis Obispo County. A separate PSD application will be filed with EPA Region IX to obtain the necessary permit for the proposed modification, and will include the emissions and air quality analyses contained in the AFC. The District has been delegated authority by EPA to implement and enforce most other federal requirements that are applicable to the facility, including the new source performance standards. Compliance with the District regulations ensures compliance and consistency with the corresponding federal requirements as well. The facility will also be required to comply with the federal Acid Rain requirements (Title IV). Since the District has received delegation for implementing Title IV through its Title V permit program, MBPP will apply for a modification to the District Title V permit that will include the necessary requirements for compliance with the Title IV Acid Rain provisions.

As discussed in AFC Section 6.2.5, Regulatory Setting, the federal PSD program requirements apply on a pollutant-specific basis to the following:

- a new major facility that will emit 100 tpy or more, if it is one of the 20 PSD source categories in the federal Clean Air Act, or a new facility that will emit 250 tpy or more; or
- a major modification to an existing major facility that will result in net emissions increases in excess of the significant emissions levels shown in Table 6.2-40.

The proposed Project is a major modification to an existing major facility. Therefore, it is subject to the EPA PSD regulations. The emissions levels summarized in Table 6.2-40 showed that the Project will result in a net increase in PM_{10} emissions that exceeds the PSD significance threshold for that pollutant, and is therefore subject to PSD review for that pollutant. PSD review is not required for any other pollutant.

As discussed above, the proposed major modification to a major stationary source result in an increase in PM_{10} emissions that exceeds the PSD trigger level, and therefore BACT must be used for this pollutant. The discussion of BACT for this pollutant is provided below in Section 6.2.6.3.

40 CFR §52.21(k) requires that the modeling be conducted with appropriate meteorological and topographic data necessary to estimate impacts. The MBPP modeling analyses used US Geological Service topographic data for the surrounding area and weather data gathered onsite by PG&E.

40 CFR §52.21(k) also requires a demonstration that emission increases subject to the PSD program will not interfere with the attainment or maintenance of any NAAQS for each applicable pollutant. As shown in Table 6.2-38, the proposed Project will not cause or contribute to an exceedance of any federal ambient air quality standard. The modeling analysis is discussed in detail in Section 6.2.6.2.

For an application that triggers PSD modeling requirements, 40 CFR §52.21(m) requires that ambient monitoring data be gathered for one year preceding the submittal of a complete application, or an EPA-approved representative time period. However, if the air quality impacts of the facility do not exceed the specified *de minimis* levels, on a pollutant-specific basis, the facility is exempted from the preconstruction monitoring requirement. The air quality impacts of the Project's PM_{10} emissions are above the applicable *de minimis* level, as shown in Table 6.2-41, and therefore the exemption does not apply to the proposed Project. However, the CARB- and District-operated ambient monitoring stations in Morro Bay, Grover City, and San Luis Obispo were shown to be representative of existing air quality in the vicinity of the Project, and were used to determine existing ambient concentrations.

40 CFR §52.21(o) requires the applicant to provide an analysis of the impairment to visibility, soils, and vegetation that would occur as a result of the proposed Project. These analyses are provided in Sections 6.2.6.5, 6.4, and 6.6 of the AFC, respectively.

40 CFR §52.21(p) requires applicants to demonstrate that emissions from a new or modified facility will not cause or contribute to the exceedance of any NAAQS or any applicable Class I PSD increment. Impacts on visibility must also be evaluated. The analysis of impacts on the nearby Class I area, the San Rafael Wilderness area, is included in Section 6.2.6.5.

6.2.7.2 Consistency with State Requirements

State law establishes local air pollution control districts and air quality management districts with the principal responsibility for regulating emissions from stationary sources. As discussed in Section 6.2.5.1, the facility is under the local jurisdiction of the SLOCAPCD, and compliance with District regulations will ensure compliance with state air quality requirements.

6.2.7.3 Consistency with Local Requirements: SLOCAPCD

The SLOCAPCD has been delegated responsibility for implementing local, state, and federal air quality regulations (except PSD) in San Luis Obispo County. The facility is subject to SLOCAPCD regulations that apply to new sources of emissions, to the prohibitory regulations that specify emission standards for individual equipment categories, and to the requirements for evaluation of impacts from toxic air pollutants. The following sections include the evaluation of facility compliance with the applicable SLOCAPCD requirements.

Under the regulations that govern new sources of emissions, MBPP is required to secure a preconstruction Determination of Compliance from the SLOCAPCD (Rule 223), as well as demonstrate continued compliance with regulatory limits when the facility becomes operational. The preconstruction review includes a demonstration that the facility will use BACT and will provide the necessary emission offsets.

6.2.7.3.1 BACT

Applicable BACT levels were shown in Table 6.2-17. SLOCAPCD Rule 204 requires the new turbines to be equipped with BACT for an emissions increase of NOx, VOC, SOx, CO, and PM_{10}

(criteria pollutants) in excess of 25 pounds per day (250 lb/day for CO). As shown in Table 6.2-51, BACT is required for NOx, VOC, CO, and PM_{10}. The calculation of facility emissions was discussed in AFC Section 6.2.6.2.

TABLE 6.2-51
BEST AVAILABLE CONTROL TECHNOLOGY REQUIREMENTS
SLOCAPCD

POLLUTANT	APPLICABILITY LEVEL (lbs/day)	FACILITY NET INCREASE (lbs/day)	BACT REQUIRED
NOx	25	2,784.0	YES
SO_2	25	134.4	YES
VOC	25	644.3	YES
PM_{10}	25	1203.2	YES
CO	250	12,119.2	YES

BACT for the applicable pollutants was determined by reviewing the BAAQMD BACT Guidelines Manual, the South Coast Air Quality Management District BACT Guidelines Manual, the most recent Compilation of California BACT Determinations, CAPCOA (2nd Ed., November 1993), and EPA's BACT/LAER Clearinghouse. A summary of the review is provided in Appendix 6.2-6. For the gas turbines, the District considers BACT to be the most stringent level of demonstrated emission control that is feasible. The turbines at MBPP will use the BACT measures discussed below at the facility.

As a BACT measure, Duke will limit the fuels burned at the facility to natural gas, a clean burning fuel. Liquid fuels will not be fired at the facility. Burning of liquid fuels in the gas turbine combustors would result in greater criteria pollutant emissions than if the units burned only gaseous fuels. Hence, this measure acts to minimize the formation of all criteria air pollutants.

BACT for NOx Emissions

BACT for NOx emissions will be the use of low NOx emitting equipment and add-on controls. For the MBPP Project, Duke has selected gas turbines equipped with dry low-NOx combustors. The gas turbine dry low-NOx combustors will generate approximately 25 to 35 ppmvd NOx, corrected to 15% O_2. In addition, the turbines will be equipped with SCR systems to further reduce NOx emissions to 2.5 ppmvd NOx, corrected to 15% O_2, on a one-hour average basis. This emission rate has recently been accepted by the BAAQMD and USEPA Region IX as meeting the BACT requirements for NOx from gas turbines, and is consistent with ARB's recently released draft guidelines. The BAAQMD and SCAQMD BACT Guideline determinations for NOx from gas turbines are shown in Appendix 6.2-6. A top-down BACT analysis for NOx is also provided.

BACT for CO Emissions

BACT for CO emissions will be achieved by use of gas turbines equipped with dry low-NOx combustors and oxidation catalysts. Dry low-NOx combustors emit low levels of combustion CO while still maintaining low NOx formation. With this dry low-NOx technology and catalysts, the turbines will meet a CO limit of 6 ppmvd, corrected to 15% O_2. The BAAQMD has recently revised its BACT determination for gas turbines from 6 ppm to 10 ppm CO, corrected to 15% O_2. The BAAQMD BACT guidelines indicate that BACT from large gas turbines (>23 MMBtu/hr heat input) is an exhaust concentration not to exceed 10 ppmvd CO, corrected to 15% O_2. CO emissions from the MBPP gas turbines are consistent with this BACT requirement. A review of recent BACT determinations for CO from gas turbines is provided in Appendix 6.2-6.

ARB has suggested a BACT level of 6 ppmvd at 15% O_2, based principally on the use of oxidation catalyst technology, for CO nonattainment areas. In attainment areas such as San Luis Obispo County, ARB has given districts the discretion to set the BACT level for CO. The applicant's proposed 6 ppm level is consistent with these requirements.

BACT for VOC Emissions

BACT for VOC emissions will be achieved by use of the gas turbine dry low-NOx combustors. As in the case of CO emission formation, dry low-NOx combustors use air to fuel ratios that result in low combustion VOC while still maintaining low NOx levels. BACT for VOC emissions from combustion devices has historically been the use of best combustion practices, as the majority of the VOC emissions are low molecular weight compounds that are not susceptible to control by the oxidation catalysts. With the use of the dry low-NOx combustors, VOC emissions leaving the stacks will not exceed 2 ppmvd, corrected to 15% O_2, with an expected compliance tolerance of 1 ppm based on current source test methods. This level of emissions is consistent with the ARB's BACT requirements for VOC.

BACT for PM_{10} and SO_2 Emissions

BACT for PM_{10} is best combustion practices and the use of gaseous fuels. Use of clean burning natural gas fuel will result in minimal particulate emissions. SO_2 emissions will also be kept at a minimum by firing natural gas.

6.2.7.3.2 Offset Requirements

In addition to the BACT requirements, District Regulation 204 requires MBPP to provide emission offsets for all net facility increases if the facility potential to emit exceeds specified levels on a pollutant-specific basis. As shown in Table 6.2-52, offsets will be required for NOx, SO_2, VOC, CO and PM_{10} emissions.

TABLE 6.2-52
SLOCAPCD OFFSET REQUIREMENTS
AND PROJECT NET EMISSIONS INCREASES
MORRO BAY POWER PLANT

POLLUTANT	OFFSET THRESHOLD (tpy)	FACILITY POTENTIAL TO EMIT (tpy)	PROJECT NET INCREASE?	OFFSETS REQUIRED?
NOx	25	292.3	YES	YES
SO_2	25	23.0	YES	YES[1]
CO	250	917.4	YES	YES
VOC	25	77.6	YES	YES
PM_{10}	25	203.2	YES	YES

(1) SO_2 offsets required under 204.B.1.a and c because SO_2 is a precursor to PM_{10};.

Creditable emissions reductions were shown in Table 6.2-22. In accordance with Rule 211, emissions reductions are required to be discounted by 20% or to be BARCT-adjusted. A 20% discount has been applied to the SO_2, CO, VOC, and PM_{10} reductions in Table 6.2-22 to determine the ERCs.

The rule requires offsets to be provided at an offset ratio of 1:1. Because SO_2 emissions contribute to PM_{10} formation in the area and VOC and NOx are both precursors to ozone, the applicant is proposing to use the excess reduction in SO_2 emissions to offset increases in PM_{10} and the excess VOC reductions to offset the remaining increases in NOx, both at a ratio of 1:1.[1]

Table 6.2-53 below summarizes the offset requirements for the Project. While most of the required offsets will be obtained from on-site emission reductions, the applicant has also obtained offsets by purchasing ERCs. The quantities and sources of ERCs are also shown in Table 6.2-53. Copies of the ERC certificates purchased from Chevron are included as Appendix 6.2-7.

1 ARB, 1999.

TABLE 6.2-53
SUMMARY OF OFFSET REQUIREMENTS (TONS/YEAR)
MORRO BAY POWER PLANT

UNIT	NOx	SO_2	CO	VOC	PM_{10}
Net Increase from New Turbines	292.3	23.0	917.4	77.6	203.2
ERCs from Shutdown of Units 1 through 4	245.7	6.64	918.3	60.9	84.2
ERCs Held by Duke: Elimination of Oil Firing Chevron ERCs	 8.19 22.92	 194.93 1.23	 0 2.62	 0 32.89	 17.22 1.92
Remaining Offsets Required (Excess)	15.49	(179.80)	(3.52)	(16.19)	99.86
Interpollutant Offsets: VOC => NOx SOx => PM_{10}	 (15.49) 	 99.86		 15.49 	 (99.86)
Net Offsets Required (Excess)	0	(79.94)	(3.52)	(0.70)	0

Rule 204 also requires project denial if SO_2, NO_2, PM_{10}, or CO air quality modeling results indicate emissions will interfere with the attainment or maintenance of the applicable ambient air quality standards or will exceed PSD increments. The modeling analyses presented in Section 6.2.6.3 show that facility emissions will not interfere with the attainment or maintenance of the applicable air quality standards.

Rule 216, Federal Part 70 Permits (Title V permit program) applies to facilities that emit more than 100 tons per year on a pollutant-specific basis. As an existing major source under this rule, MBPP has already applied for and obtained a Title V permit from the District. Under the Title V permit program, the power plant will be required to obtain a revised operating permit prior to commencing operation of the new turbines. The Phase II acid rain requirements of Rule 217 are also applicable to the facility. As a Phase II Acid Rain facility, MBPP will be required to provide sufficient allowances for every ton of SO_2 emitted during a calendar year. MBPP will obtain any necessary allowances on the current open trade market. The power plant is also required to install and operate continuous monitoring systems on the new units.

Rule 219 (Toxics New Source Review) requires new and modified sources to demonstrate that emissions of toxics will not pose a significant health risk. The analysis provided in Section 6.2.6.4.2 demonstrated compliance with the requirements of Rule 219.

The general prohibitory rules of the District applicable to the facility and the determination of compliance follow.

Rule 401 (Visible Emissions). Any visible emissions from the Project will not be darker than No. 2 when compared to a Ringlemann Chart for any period(s) aggregating three minutes in any hour. Because the facility will burn clean fuels, the opacity standard of not greater than 20% for a period or periods aggregating three minutes in any hour and the particulate emission concentrations limit of 0.15 grains per standard cubic feet of exhaust gas volume will not be exceeded.

Rule 402 (Public Nuisance). The facility will emit insignificant quantities of odorous or visible substances; therefore, the facility will comply with this regulation.

Rule 403 (Particulate Matter Emission Standards). The emissions units will have particulate matter emission rates well below the limits of the rule.

Rule 404 (Sulfur Compound Emissions). Because the Project will use only natural gas fuel, all of the Rule 404 limits will easily be complied with.

Rule 405 (Nitrogen Oxides). Emissions from the new turbines will be well below the limit in this rule.

Rule 406 (Carbon Monoxide Emission Standards and Limits). Carbon monoxide emission rates from the new turbines will be well below the limit in this rule.

Rule 429 (NOx and CO Emissions from Electric Power Generation Boilers). This rule limits NOx, CO, and ammonia emissions from the existing boilers. The CO and ammonia limits are expressed as concentrations; the NOx limit is expressed as a facilitywide daily emission rate cap. The SLOCAPCD staff has indicated that the rule, which now applies only to boilers used for electric power generation, will be amended to cover electric power generation gas turbines as well. The NOx control technology and the continuous emissions monitoring systems will ensure continued compliance with this rule.

Rule 601 (New Source Performance Standards). This rule requires monitoring of fuel; imposes limits on the emissions of NOx and SO_2; and requires source testing of stack emissions, process monitoring, and data collection and recordkeeping. All of the BACT limits imposed on the facility will be more stringent than the requirements of the NSPS emission limits. Monitoring and recordkeeping requirements for BACT will be more stringent than the requirements in this rule; therefore, the project will comply with the NSPS regulation.

6.2.8 CUMULATIVE AIR QUALITY IMPACTS ANALYSIS

To ensure that potential cumulative impacts of the Project and other nearby projects are adequately considered, a cumulative impacts analysis will be conducted in accordance with the protocol included as Appendix 6.2-8.

6.2.9 MITIGATION

Mitigation will be provided for all emissions increases from the Project in the form of offsets, as required under District regulations.

6.2.10 REFERENCES

ARB. Emission Inventory Criteria and Guidelines Report for the Air Toxics "Hot Spots" Program, May 15, 1997.

ARB. Proposed Guidance for Power Plant Siting and Best Available Control Technology. June 23, 1999.

ARB. Proposed Risk Management Guidance for the Permitting of New Stationary Diesel-Fueled Engines. Draft, August 2000.

ARB. Reference Document for California Statewide Modeling Guideline. April 1989.

CAPCOA. Air Toxics "Hot Spots" Program Revised 1992 Risk Assessment Guidelines. October 1993.

CARNOT. Assessment of Health Risks Associated with Fuel Oil Utilization and Critique of AB 2588 Risk Assessment for MBPP. February 1994.

Office of Environmental Health Hazard Assessment. Acute and Chronic Exposure Levels Developed by OEHHA as of May 2000.

Office of Environmental Health Hazard Assessment. Hot Spots Unit Risk and Cancer Potency Values. June 9, 1999.

Pacific Gas and Electric Company. Revised Air Toxics "Hot Spots" Risk Assessment for MBPP. September 9, 1991.

Smith, T.B., W.D. Sanders, and D.M. Takeuchi. Application of Climatological Analysis to Minimize Air Pollution Impacts in California, Final Report on ARB Agreement A2-119-32. August 1984.

South Coast Air Quality Management District. "Risk Assessment Procedures for Rules 1401 and 212," Version 4.1, November 1998.

U.S. EPA. Compilation of Emission Factors. AP-42. Revised 7/00.

U.S. EPA. Guideline on Air Quality Models, 40 CFR, Part 51, Appendix W. July 1, 1999.

U.S. EPA. On-Site Meteorological Program Guidance for Regulatory Model Applications, EPA-450/4-87-013. August 1995.

U.S. EPA. Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised, EPA-454/R-92-019. October 1992.

U.S. EPA. Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD), EPA-450/4-87-007. May 1987.

U.S. EPA. Guideline for Determination of Good Engineering Practice Stack Height. June 1985.

Figure 6.2-1

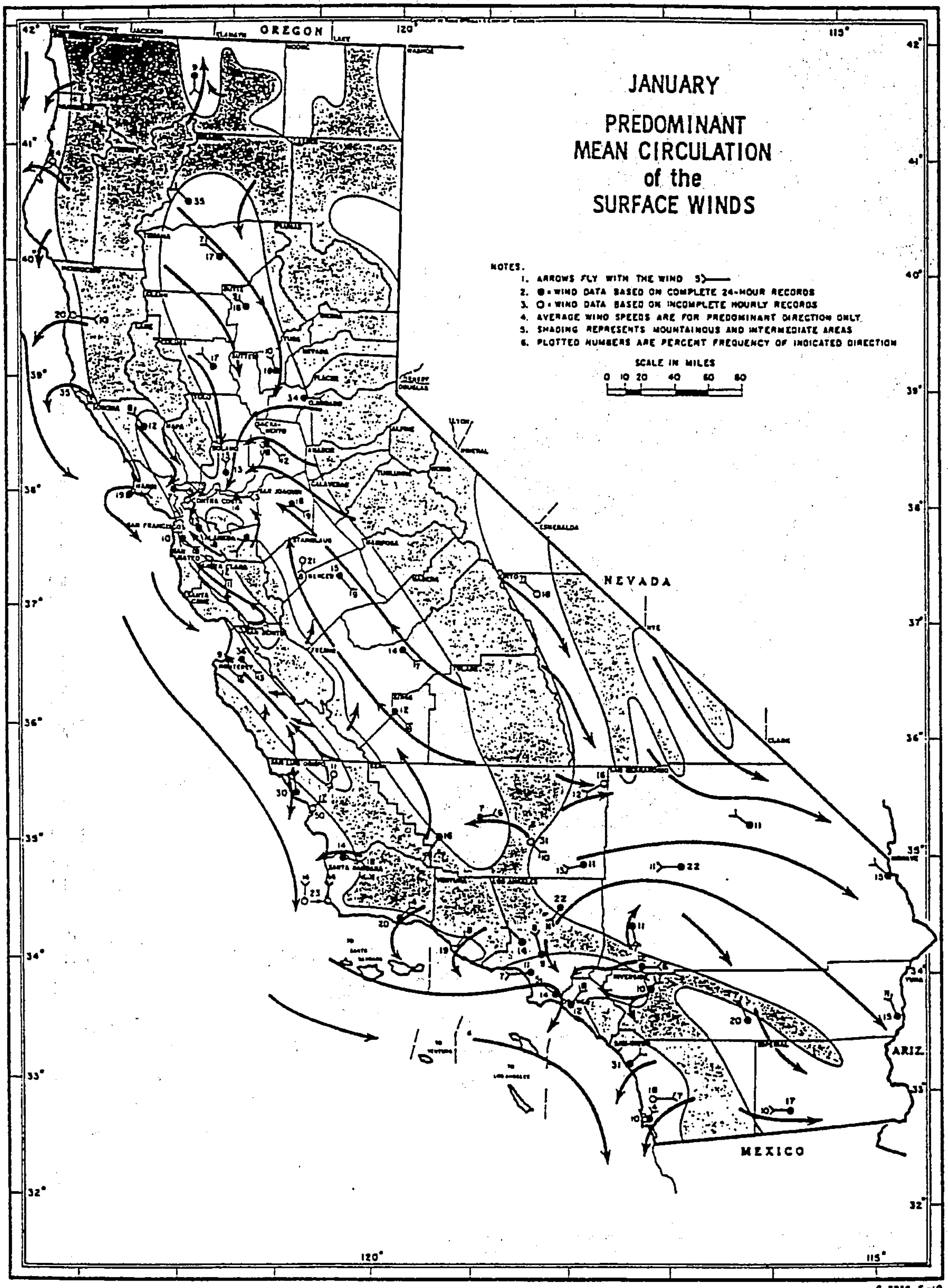

JANUARY
PREDOMINANT
MEAN CIRCULATION
of the
SURFACE WINDS
NOTES.
1. ARROWS FLY WITH THE WIND 5)——
2. ● = WIND DATA BASED ON COMPLETE 24-HOUR RECORDS
3. ○ = WIND DATA BASED ON INCOMPLETE HOURLY RECORDS
4. AVERAGE WIND SPEEDS ARE FOR PREDOMINANT DIRECTION ONLY
5. SHADING REPRESENTS MOUNTAINOUS AND INTERMEDIATE AREAS
6. PLOTTED NUMBERS ARE PERCENT FREQUENCY OF INDICATED DIRECTION
SCALE IN MILES
0 10 20 40 60 80
OREGON
NEVADA
ARIZ.
MEXICO
120°
115°
42°
41°
40°
39°
38°
37°
36°
35°
34°
33°
32°
C-2238-F-10

Figure 6.2-2

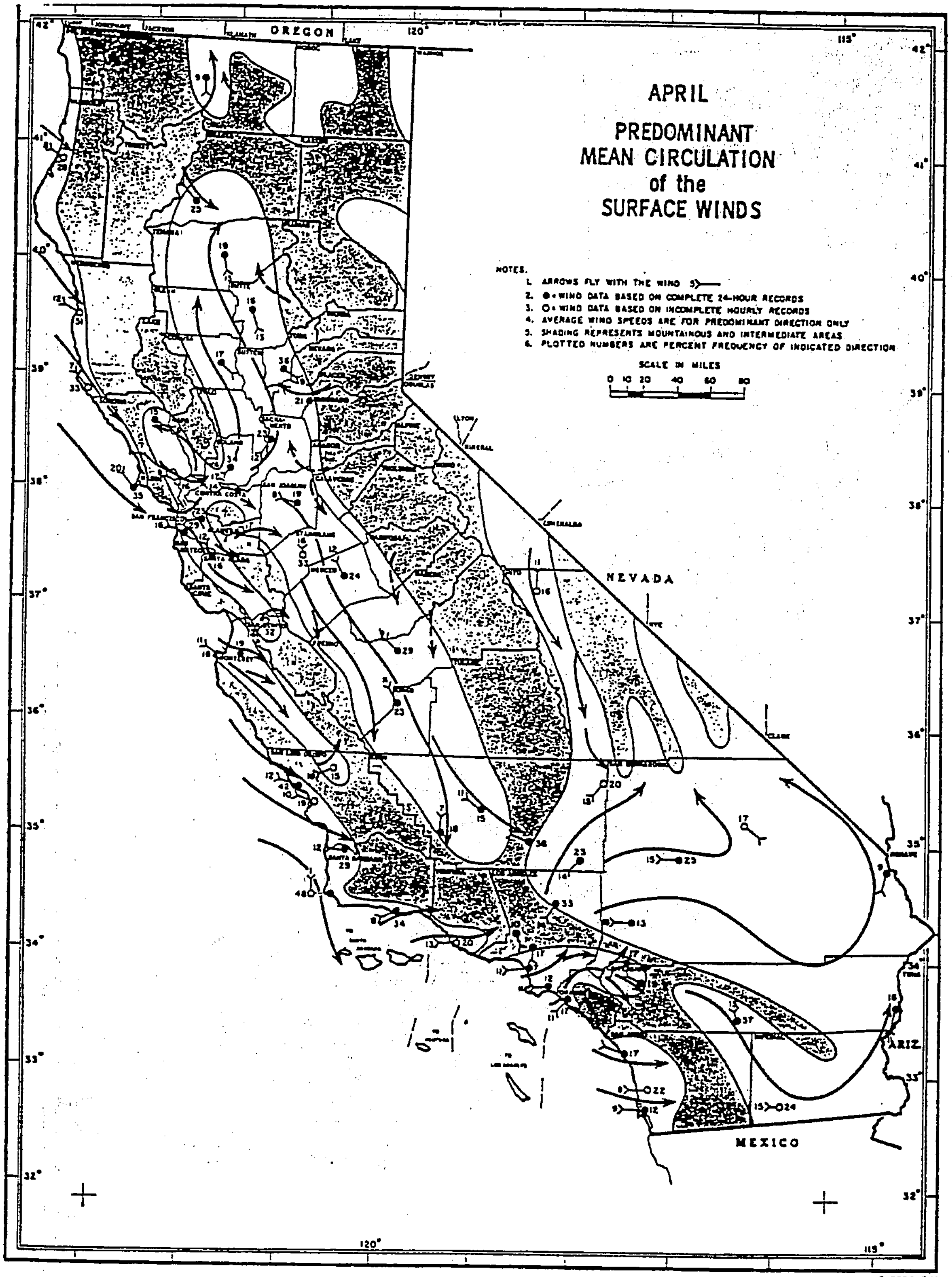

APRIL
PREDOMINANT
MEAN CIRCULATION
of the
SURFACE WINDS
NOTES.
1. ARROWS FLY WITH THE WIND 5⟩——
2. ● = WIND DATA BASED ON COMPLETE 24-HOUR RECORDS
3. ○ = WIND DATA BASED ON INCOMPLETE HOURLY RECORDS
4. AVERAGE WIND SPEEDS ARE FOR PREDOMINANT DIRECTION ONLY
5. SHADING REPRESENTS MOUNTAINOUS AND INTERMEDIATE AREAS
6. PLOTTED NUMBERS ARE PERCENT FREQUENCY OF INDICATED DIRECTION
SCALE IN MILES
0 10 20 40 60 80
OREGON
NEVADA
MEXICO
ARIZ.
120°
115°
42°
41°
40°
39°
38°
37°
36°
35°
34°
33°
32°
C-2238-F-41

Figure 6.2-3

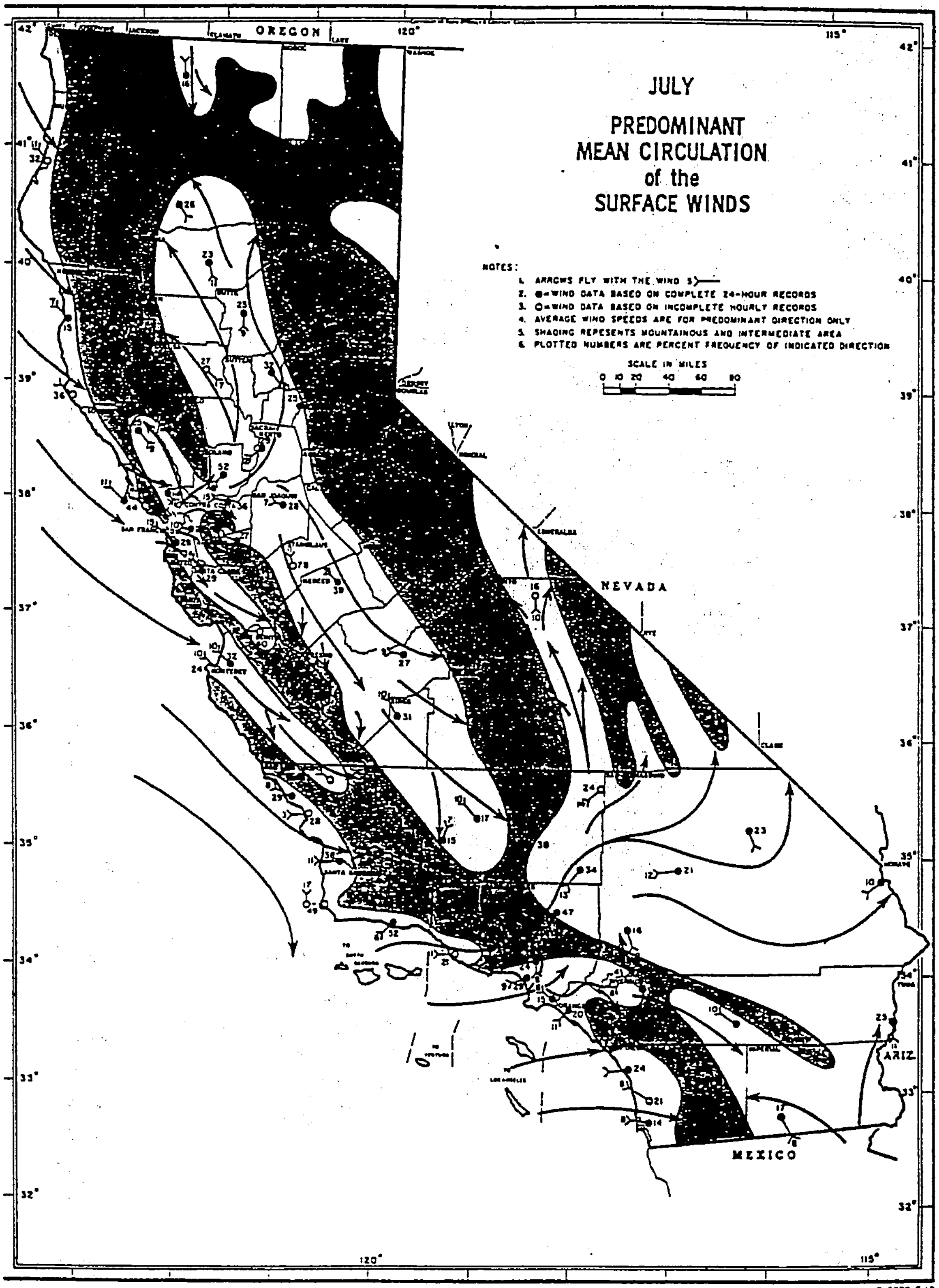
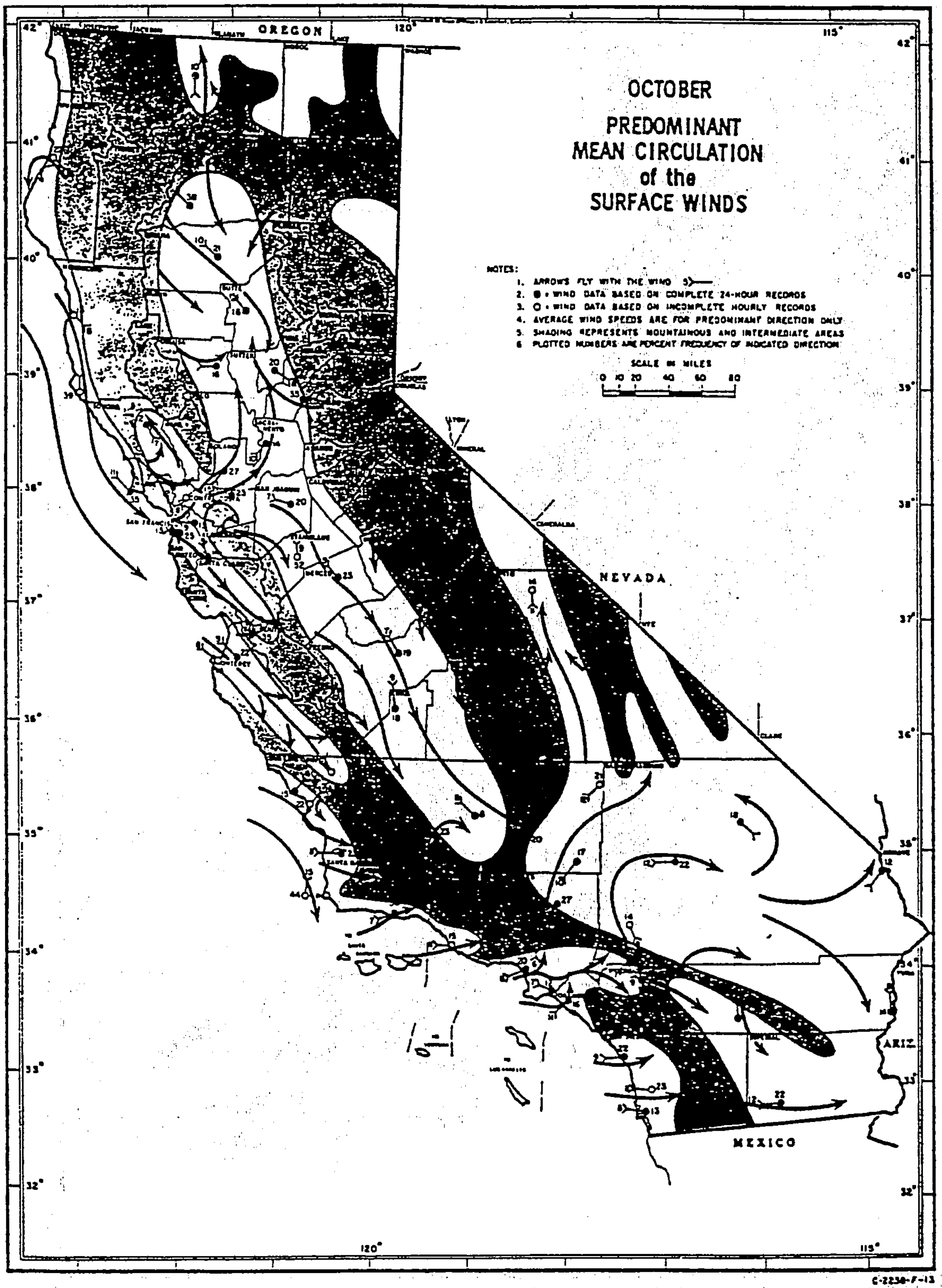
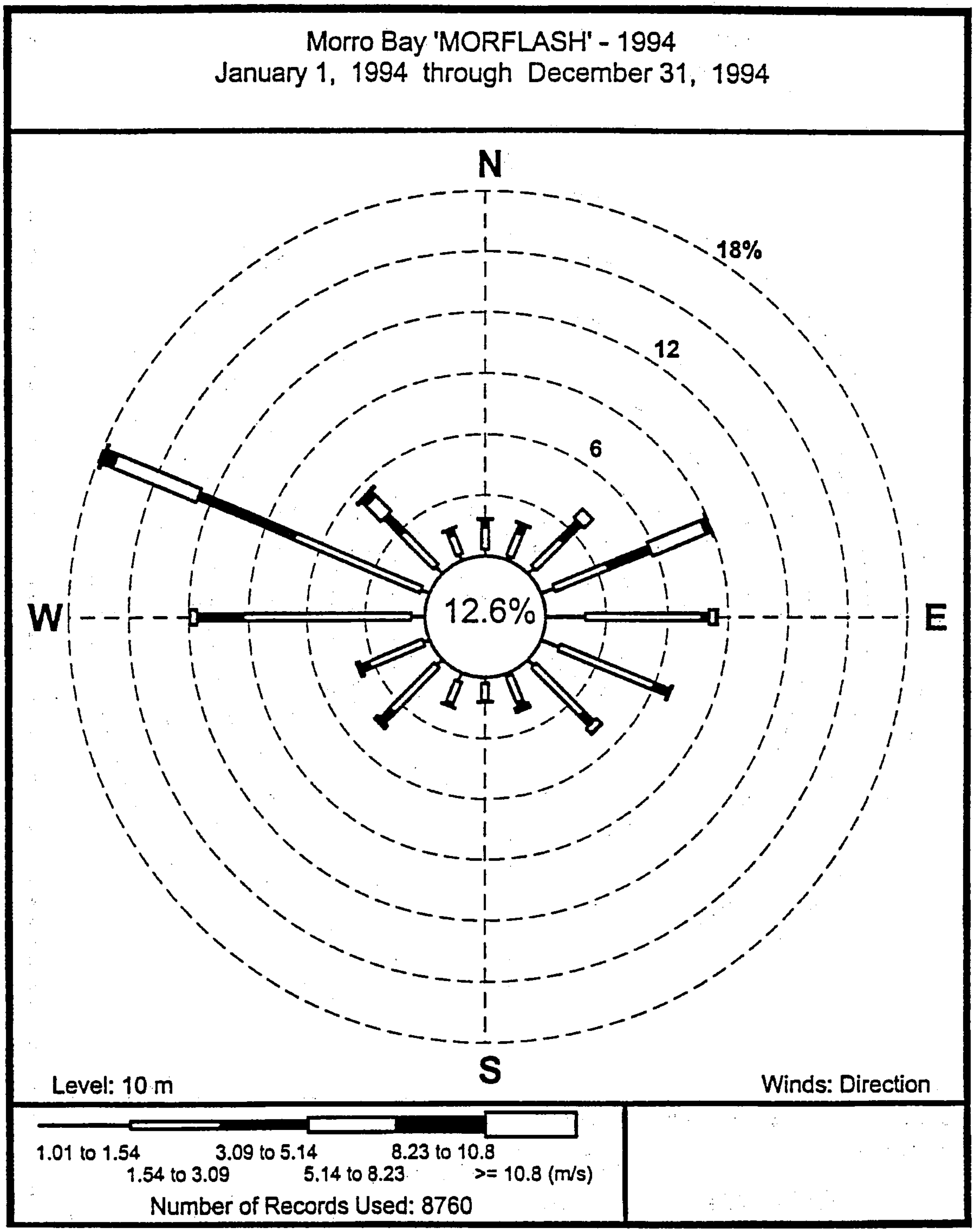

JULY
PREDOMINANT
MEAN CIRCULATION
of the
SURFACE WINDS
NOTES:
1. ARROWS FLY WITH THE WIND
2. ● = WIND DATA BASED ON COMPLETE 24-HOUR RECORDS
3. ○ = WIND DATA BASED ON INCOMPLETE HOURLY RECORDS
4. AVERAGE WIND SPEEDS ARE FOR PREDOMINANT DIRECTION ONLY
5. SHADING REPESENTS MOUNTAINOUS AND INTERMEDIATE AREA
6. PLOTTED NUMBERS ARE PERCENT FREQUENCY OF INDICATED DIRECTION
SCALE IN MILES
0 10 20 40 60 80
OREGON
NEVADA
MEXICO
ARIZ.
C-2238-F-12

Figure 6.2-4



OCTOBER
PREDOMINANT
MEAN CIRCULATION
of the
SURFACE WINDS
NOTES:
1. ARROWS FLY WITH THE WIND 5⟩——
2. ● = WIND DATA BASED ON COMPLETE 24-HOUR RECORDS
3. ○ = WIND DATA BASED ON INCOMPLETE HOURLY RECORDS
4. AVERAGE WIND SPEEDS ARE FOR PREDOMINANT DIRECTION ONLY
5. SHADING REPRESENTS MOUNTAINOUS AND INTERMEDIATE AREAS
6. PLOTTED NUMBERS ARE PERCENT FREQUENCY OF INDICATED DIRECTION
SCALE IN MILES
0 10 20 40 60 80
OREGON
NEVADA
MEXICO
ARIZ.
42°
41°
40°
39°
38°
37°
36°
35°
34°
33°
32°
120°
115°
C-2250-F-13

Figure 6.2-5a



Morro Bay 'MORFLASH' - 1994
January 1, 1994 through December 31, 1994
N
18%
12
6
W
12.6%
E
S
Level: 10 m
Winds: Direction
1.01 to 1.54
3.09 to 5.14
8.23 to 10.8
1.54 to 3.09
5.14 to 8.23
>= 10.8 (m/s)
Number of Records Used: 8760

Figure 6.2-5b

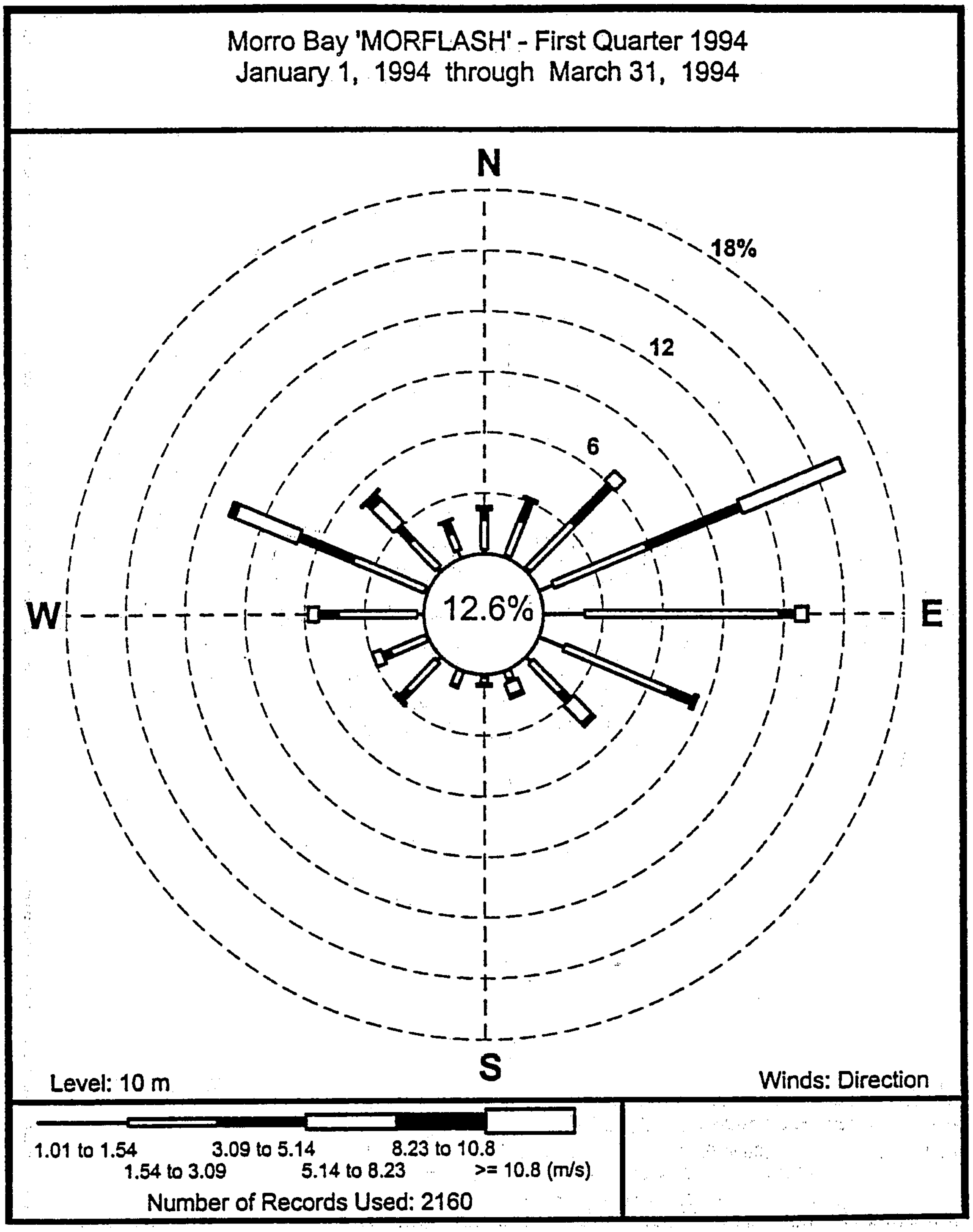

Morro Bay 'MORFLASH' - First Quarter 1994
January 1, 1994 through March 31, 1994
N
18%
12
6
W
12.6%
E
S
Level: 10 m
Winds: Direction
1.01 to 1.54
1.54 to 3.09
3.09 to 5.14
5.14 to 8.23
8.23 to 10.8
>= 10.8 (m/s)
Number of Records Used: 2160

Figure 6.2-5c

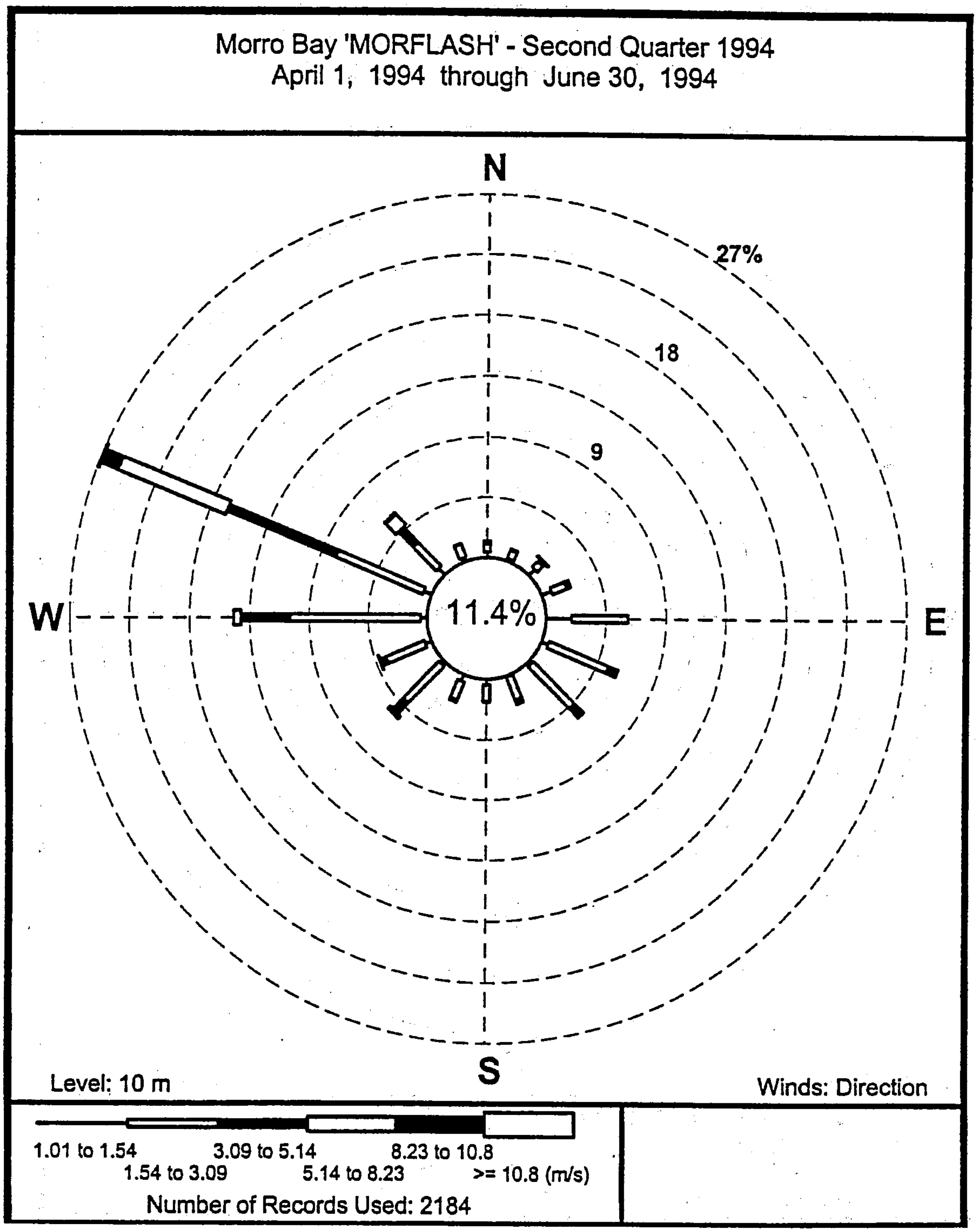
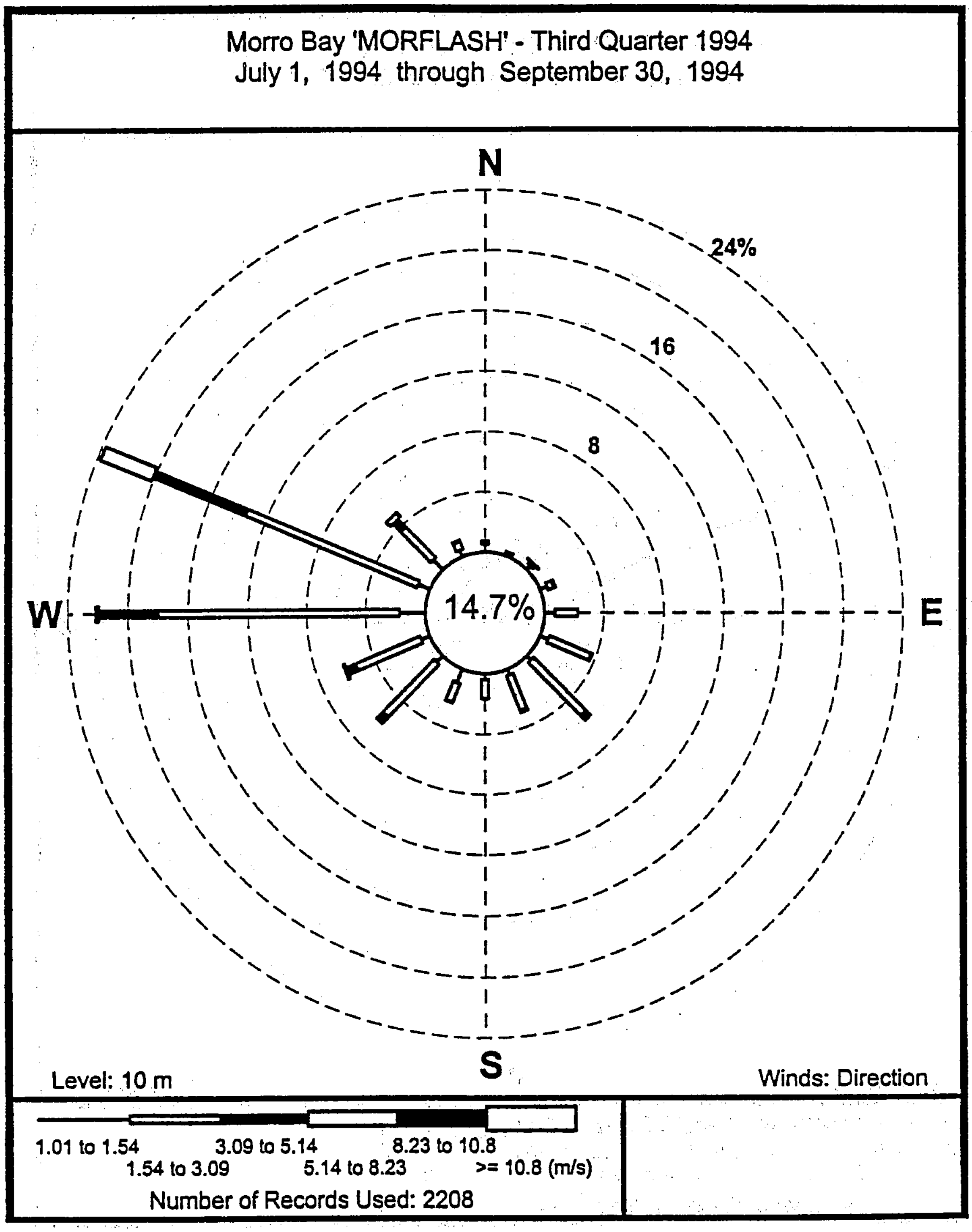

Morro Bay 'MORFLASH' - Second Quarter 1994
April 1, 1994 through June 30, 1994
N
27%
18
9
W
11.4%
E
S
Level: 10 m
Winds: Direction
1.01 to 1.54
3.09 to 5.14
8.23 to 10.8
1.54 to 3.09
5.14 to 8.23
>= 10.8 (m/s)
Number of Records Used: 2184

Figure 6.2-5d



Morro Bay 'MORFLASH' - Third Quarter 1994
July 1, 1994 through September 30, 1994
N
24%
16
8
W
14.7%
E
S
Level: 10 m
Winds: Direction
1.01 to 1.54
1.54 to 3.09
3.09 to 5.14
5.14 to 8.23
8.23 to 10.8
>= 10.8 (m/s)
Number of Records Used: 2208

Figure 6.2-5e

Morro Bay 'MORFLASH' - Fourth Quarter 1994
October 1, 1994 through December 31, 1994

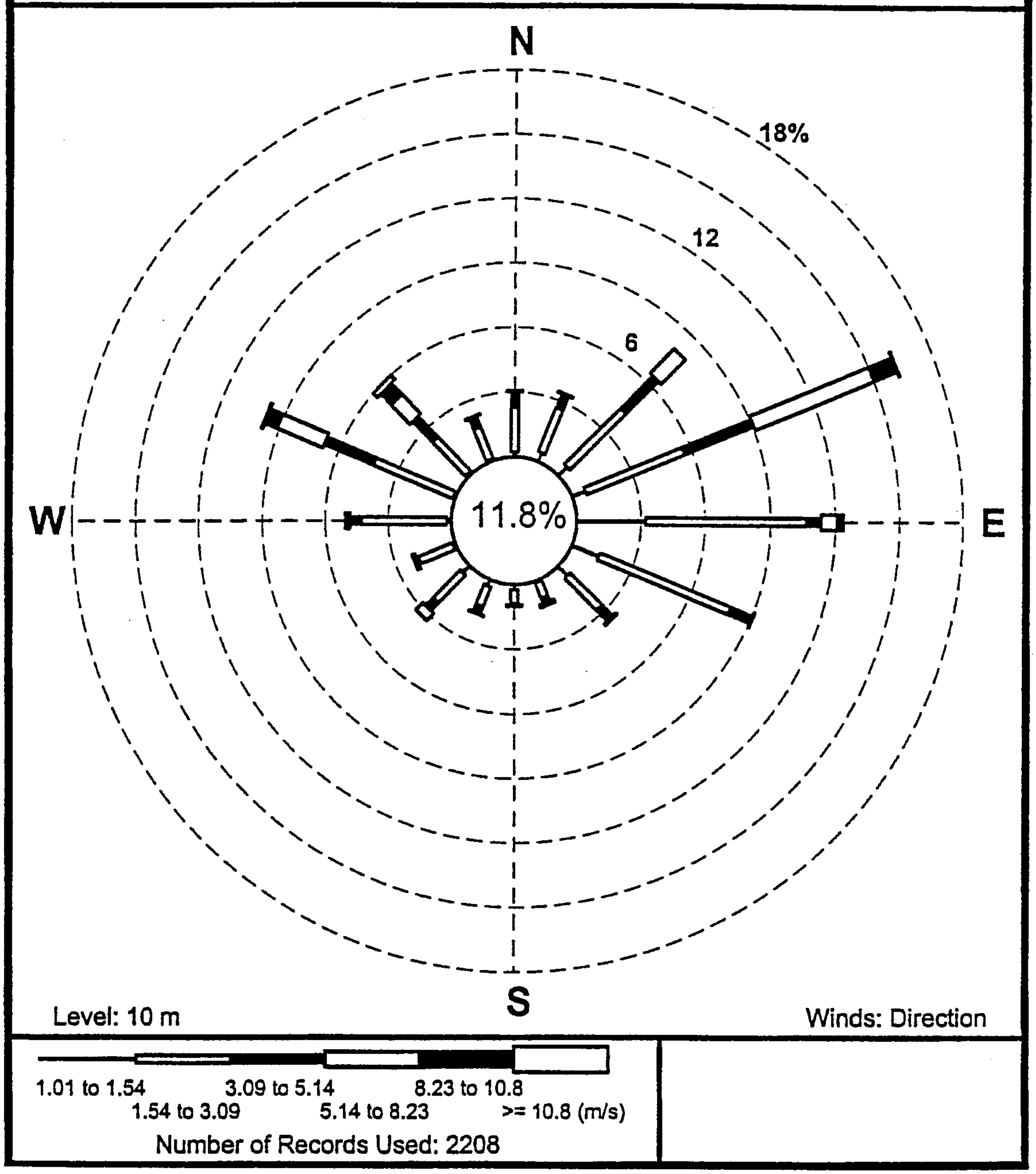
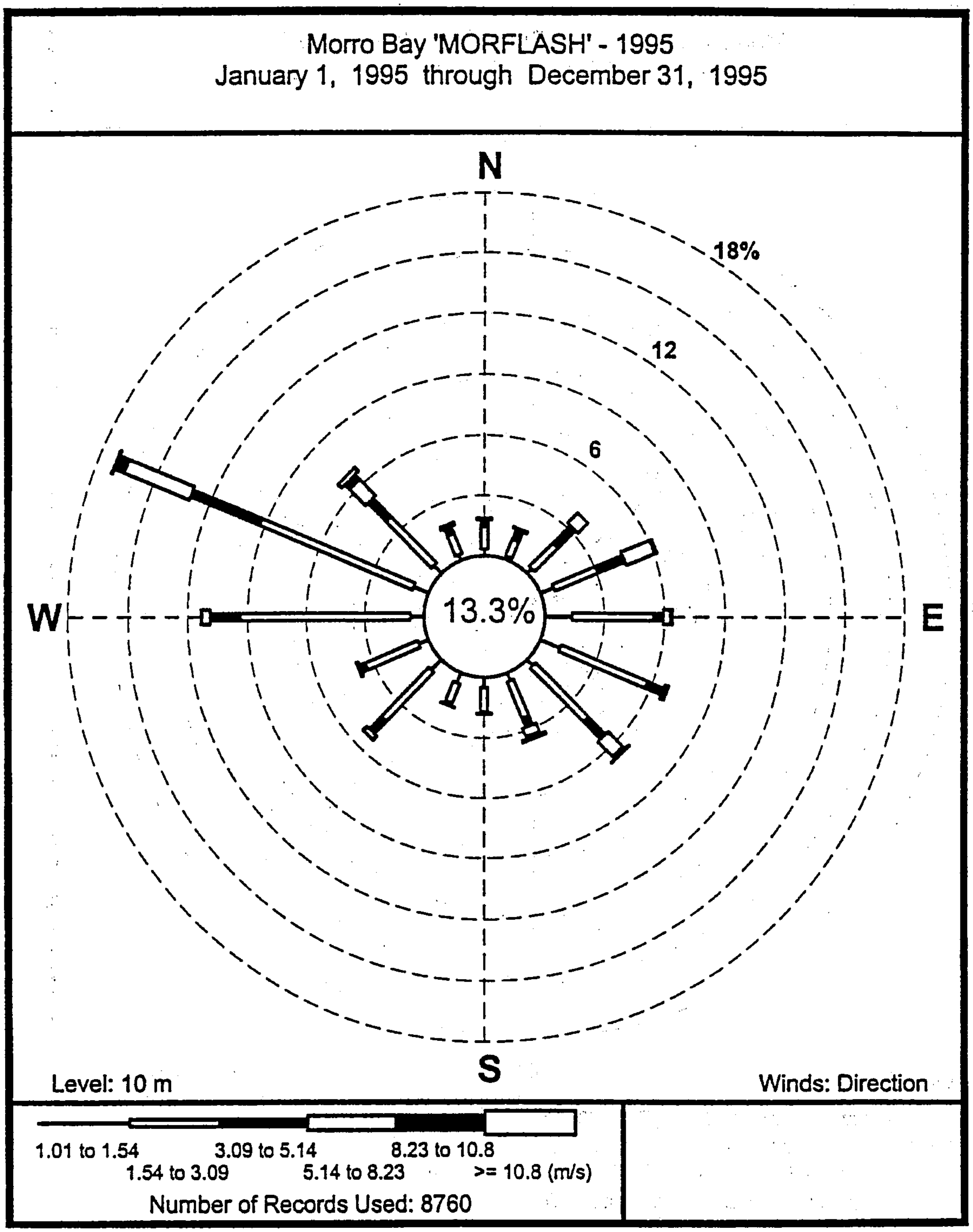
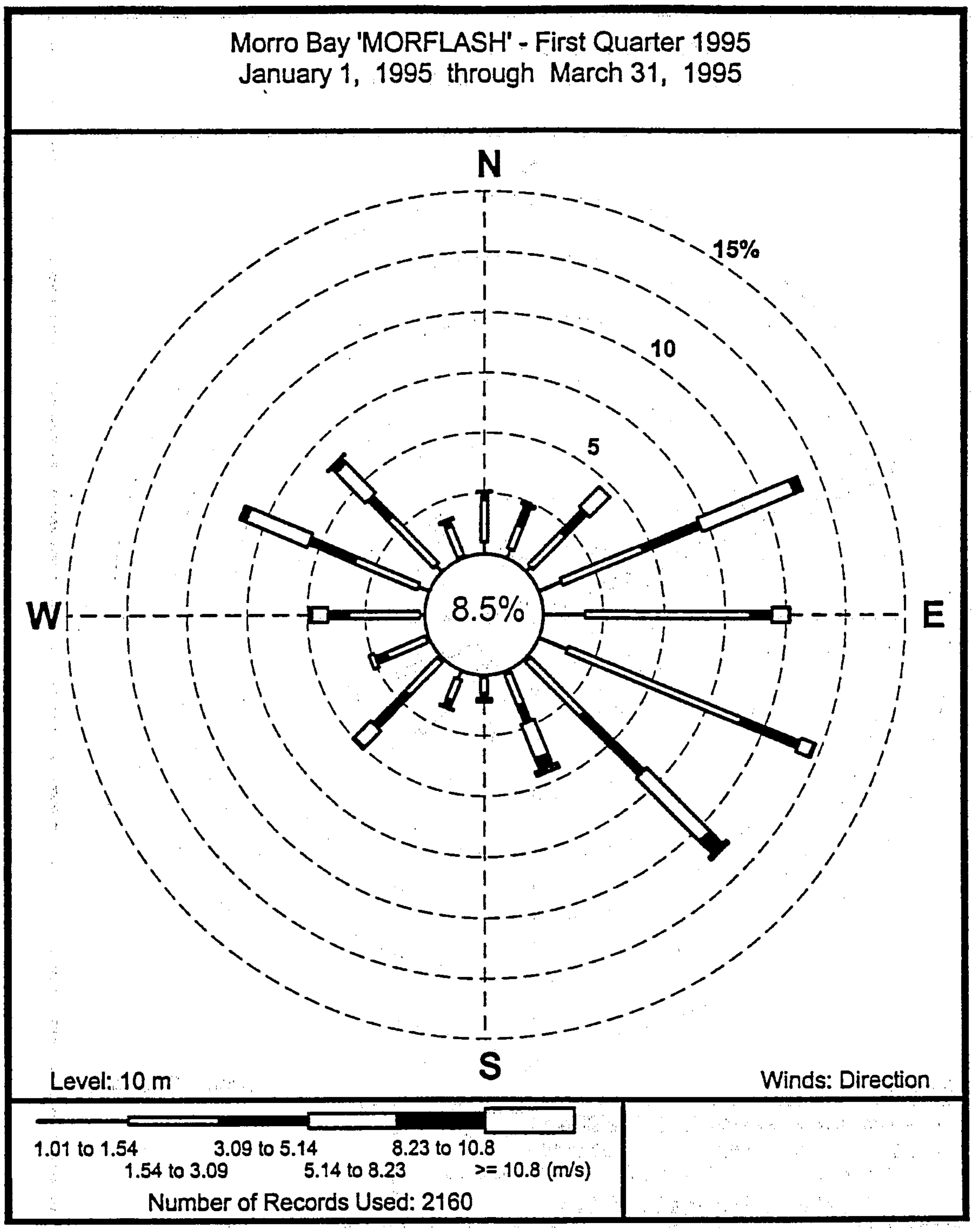


Figure 6.2-6a



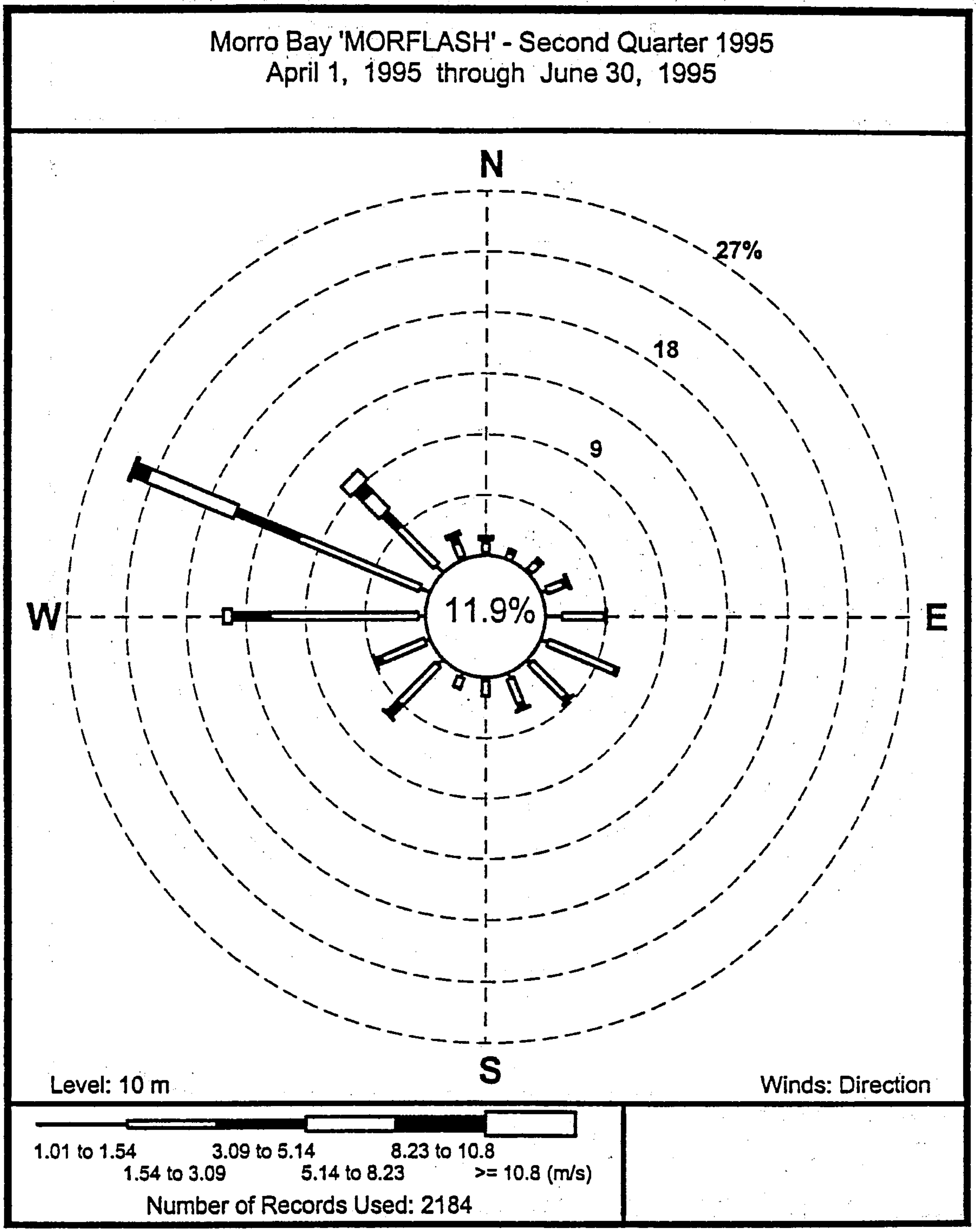
Morro Bay 'MORFLASH' - 1995
January 1, 1995 through December 31, 1995
N
18%
12
6
W
13.3%
E
S
Level: 10 m
Winds: Direction
1.01 to 1.54
3.09 to 5.14
8.23 to 10.8
1.54 to 3.09
5.14 to 8.23
>= 10.8 (m/s)
Number of Records Used: 8760

Figure 6.2-6b



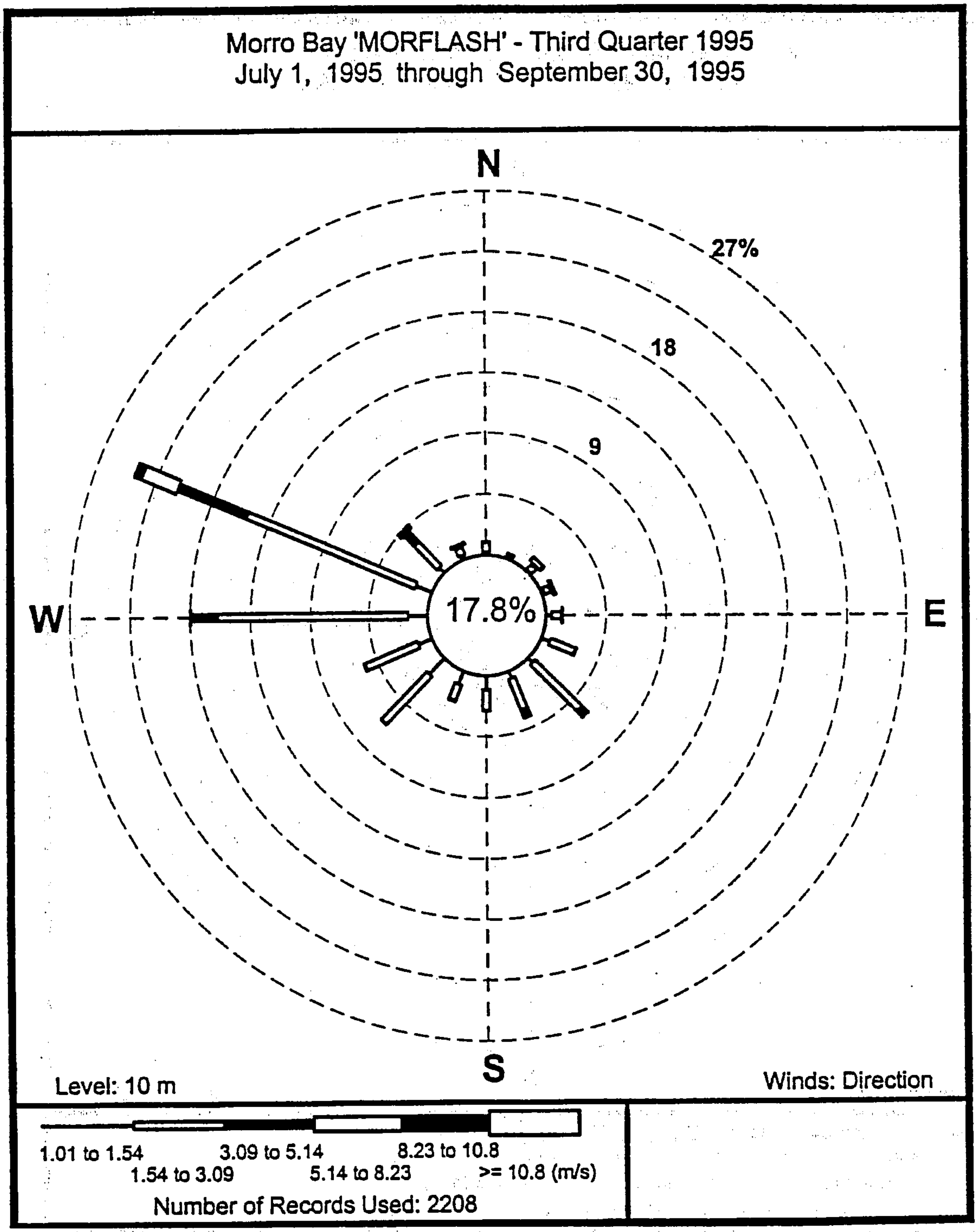
Morro Bay 'MORFLASH' - First Quarter 1995
January 1, 1995 through March 31, 1995
N
15%
10
5
W
8.5%
E
S
Level: 10 m
Winds: Direction
1.01 to 1.54
3.09 to 5.14
8.23 to 10.8
1.54 to 3.09
5.14 to 8.23
>= 10.8 (m/s)
Number of Records Used: 2160

Figure 6.2-6c



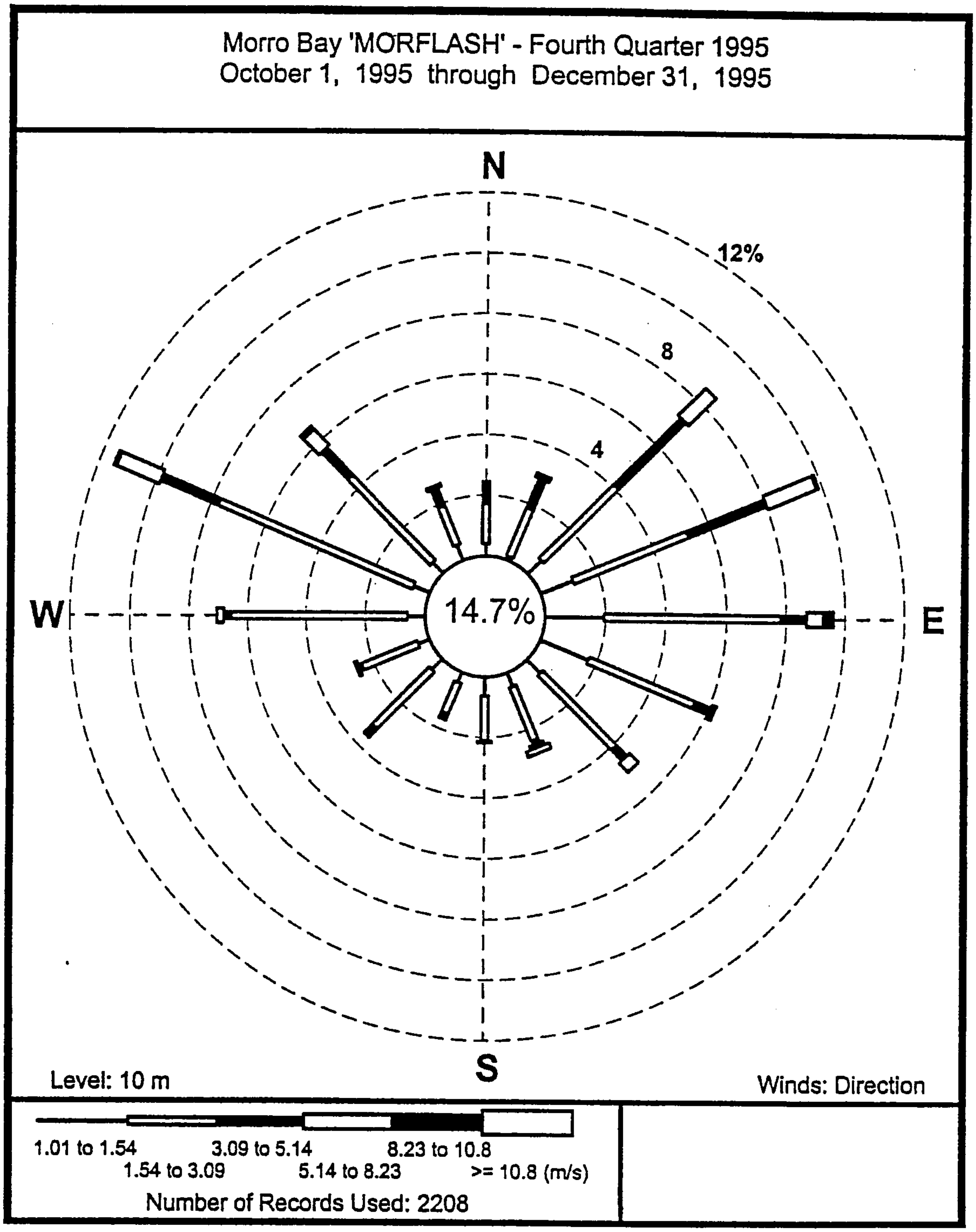
Morro Bay 'MORFLASH' - Second Quarter 1995
April 1, 1995 through June 30, 1995
N
27%
18
9
W
11.9%
E
S
Level: 10 m
Winds: Direction
1.01 to 1.54
3.09 to 5.14
8.23 to 10.8
1.54 to 3.09
5.14 to 8.23
>= 10.8 (m/s)
Number of Records Used: 2184

Figure 6.2-6d



Morro Bay 'MORFLASH' - Third Quarter 1995
July 1, 1995 through September 30, 1995
N
27%
18
9
W
17.8%
E
S
Level: 10 m
Winds: Direction
1.01 to 1.54
3.09 to 5.14
8.23 to 10.8
1.54 to 3.09
5.14 to 8.23
>= 10.8 (m/s)
Number of Records Used: 2208

Figure 6.2-6e



Morro Bay 'MORFLASH' - Fourth Quarter 1995
October 1, 1995 through December 31, 1995
N
12%
8
4
W
14.7%
E
S
Level: 10 m
Winds: Direction
1.01 to 1.54
3.09 to 5.14
8.23 to 10.8
1.54 to 3.09
5.14 to 8.23
>= 10.8 (m/s)
Number of Records Used: 2208

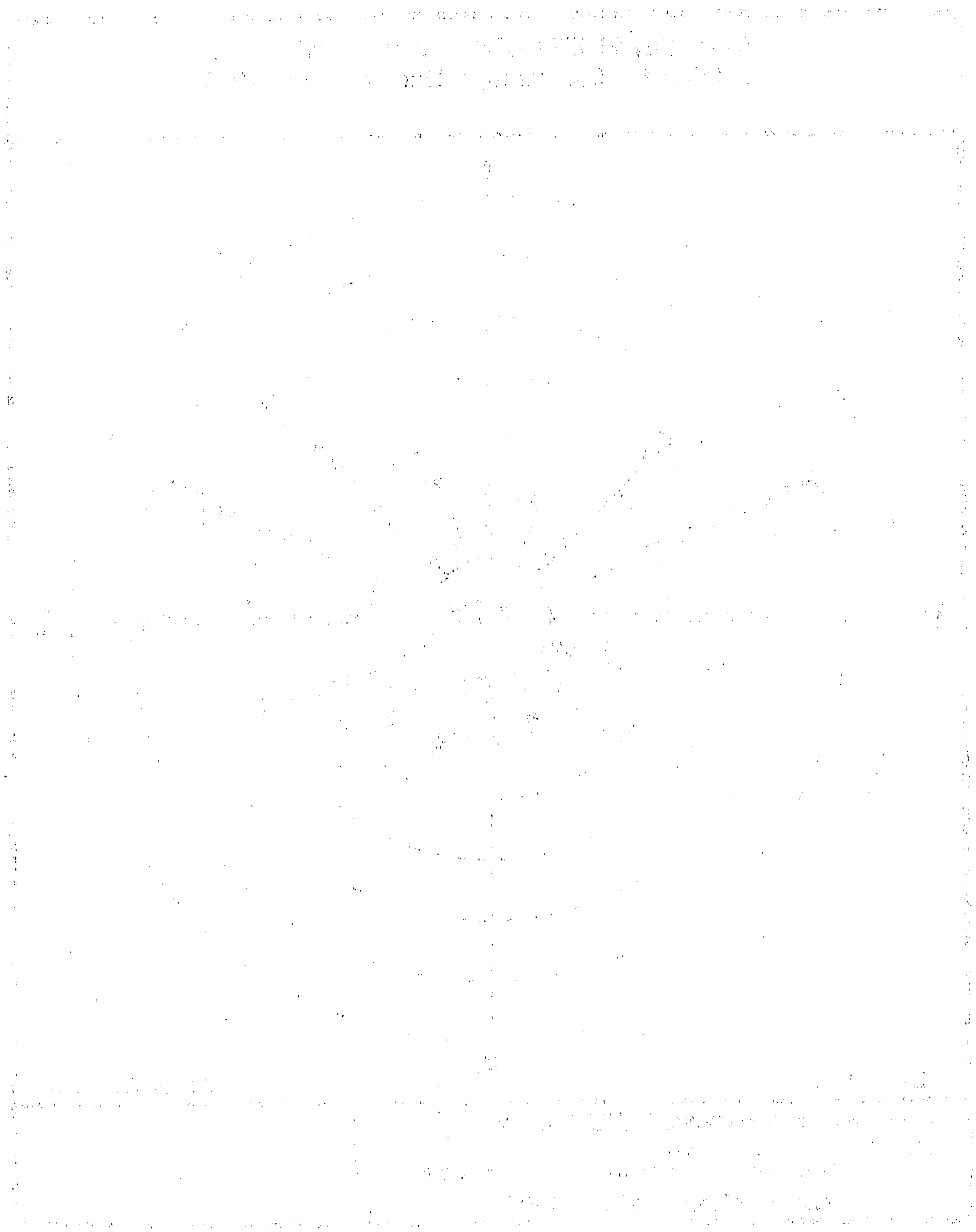
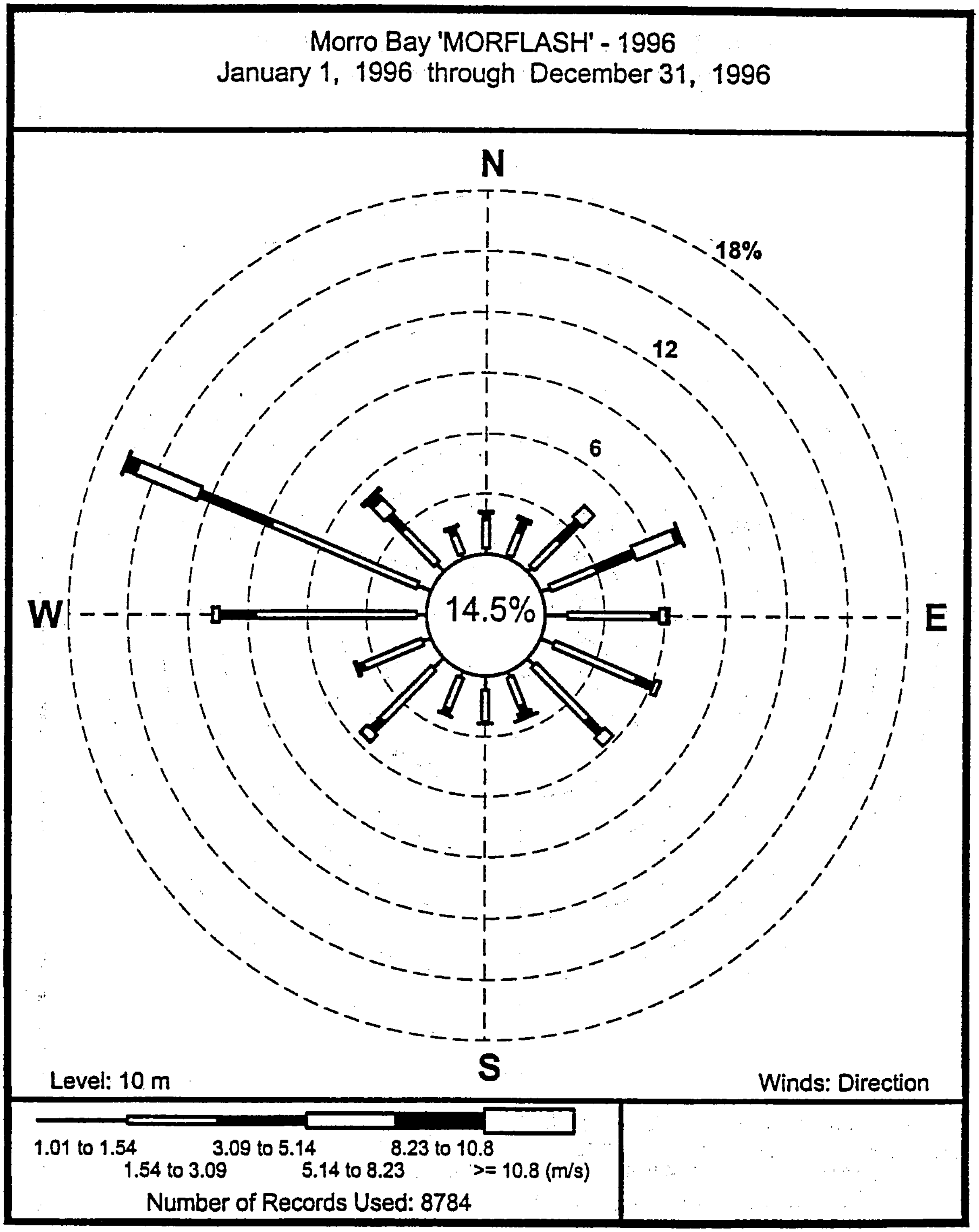
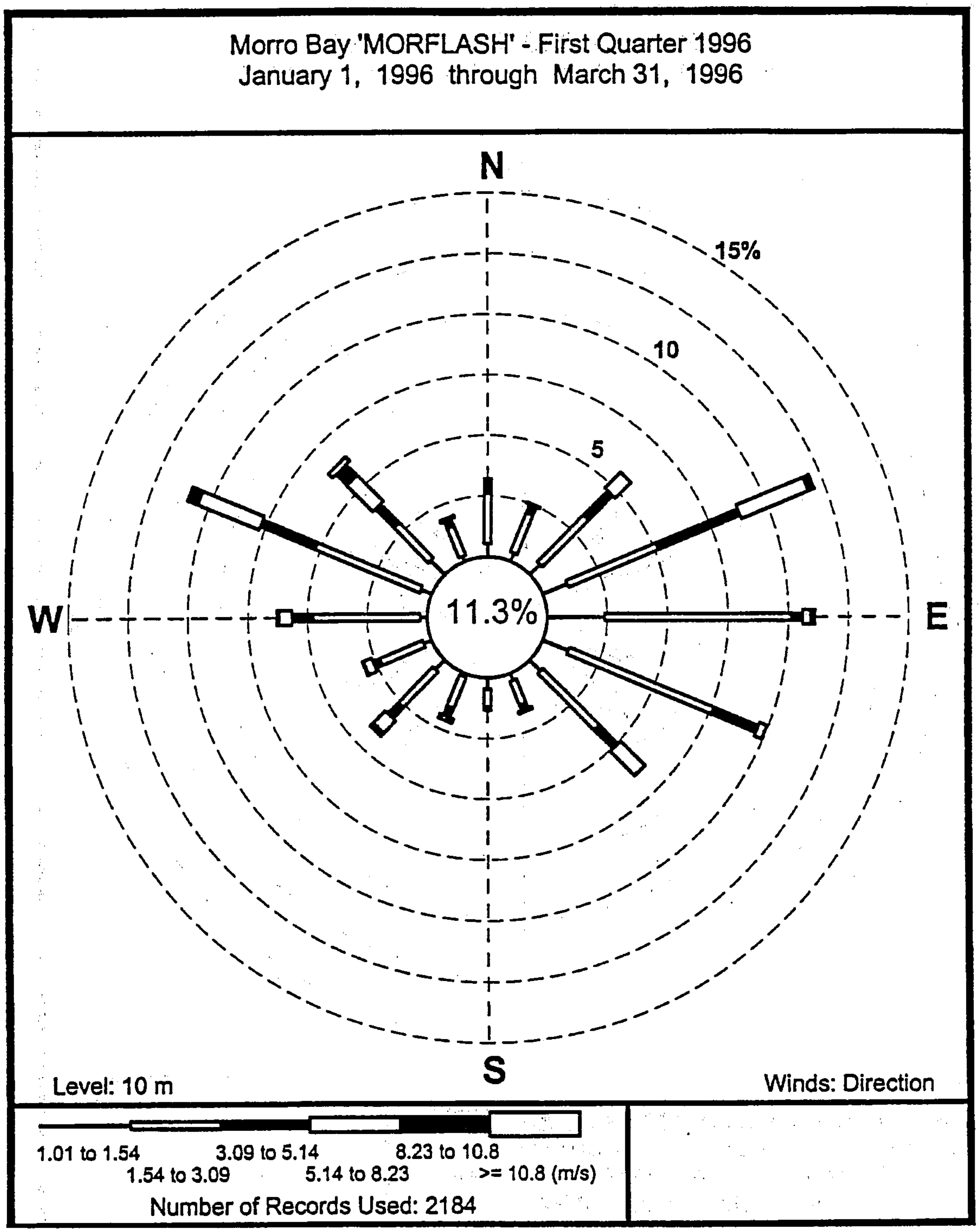


Figure 6.2-7a



Morro Bay 'MORFLASH' - 1996
January 1, 1996 through December 31, 1996
N
18%
12
6
W
14.5%
E
S
Level: 10 m
Winds: Direction
1.01 to 1.54
1.54 to 3.09
3.09 to 5.14
5.14 to 8.23
8.23 to 10.8
>= 10.8 (m/s)
Number of Records Used: 8784

Figure 6.2-7b



Morro Bay 'MORFLASH' - First Quarter 1996
January 1, 1996 through March 31, 1996
N
15%
10
5
W
11.3%
E
S
Level: 10 m
Winds: Direction
1.01 to 1.54
3.09 to 5.14
8.23 to 10.8
1.54 to 3.09
5.14 to 8.23
>= 10.8 (m/s)
Number of Records Used: 2184

Figure 6.2-7c

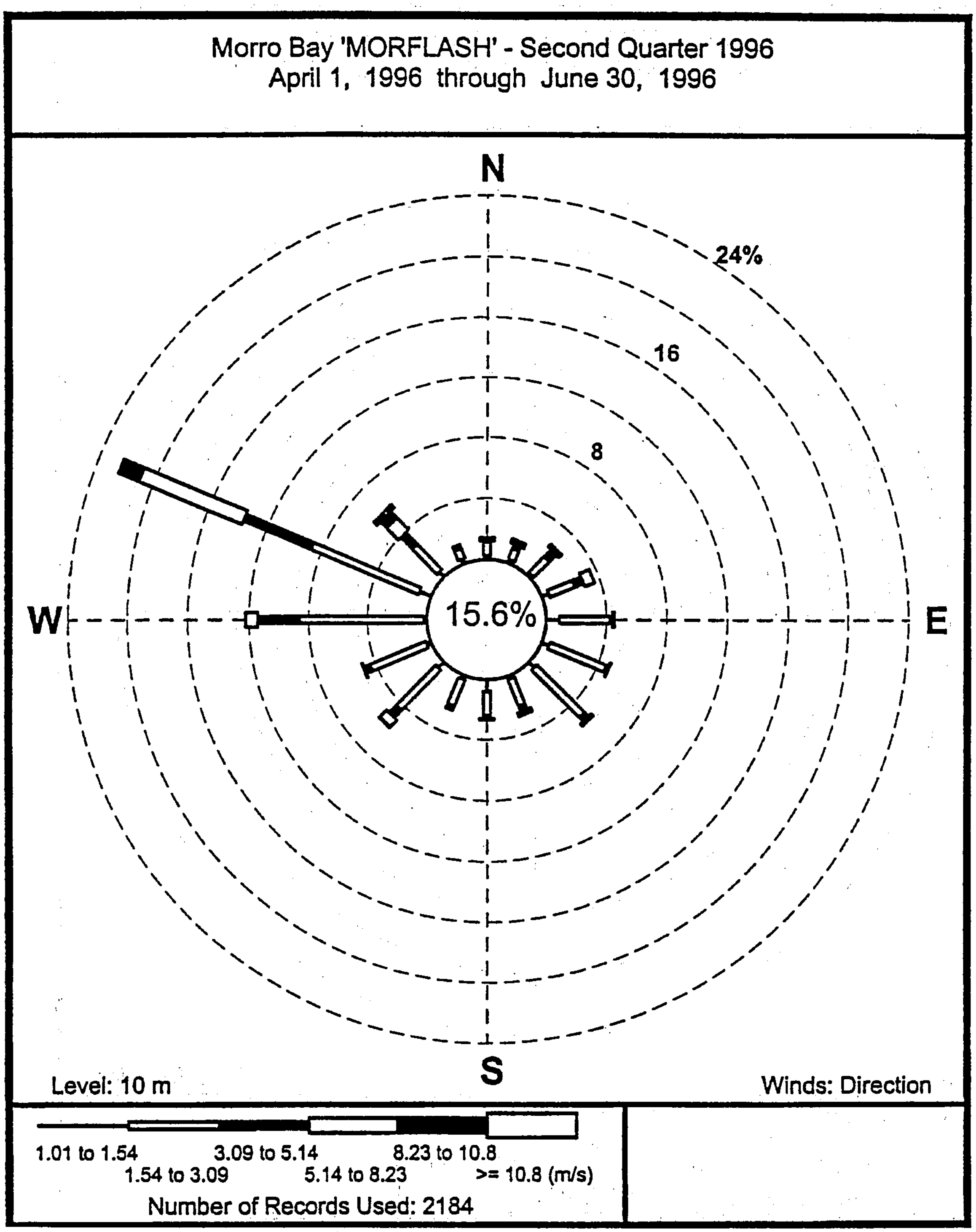

Morro Bay 'MORFLASH' - Second Quarter 1996
April 1, 1996 through June 30, 1996
N
24%
16
8
W
15.6%
E
S
Level: 10 m
Winds: Direction
1.01 to 1.54
3.09 to 5.14
8.23 to 10.8
1.54 to 3.09
5.14 to 8.23
>= 10.8 (m/s)
Number of Records Used: 2184

Figure 6.2-7d

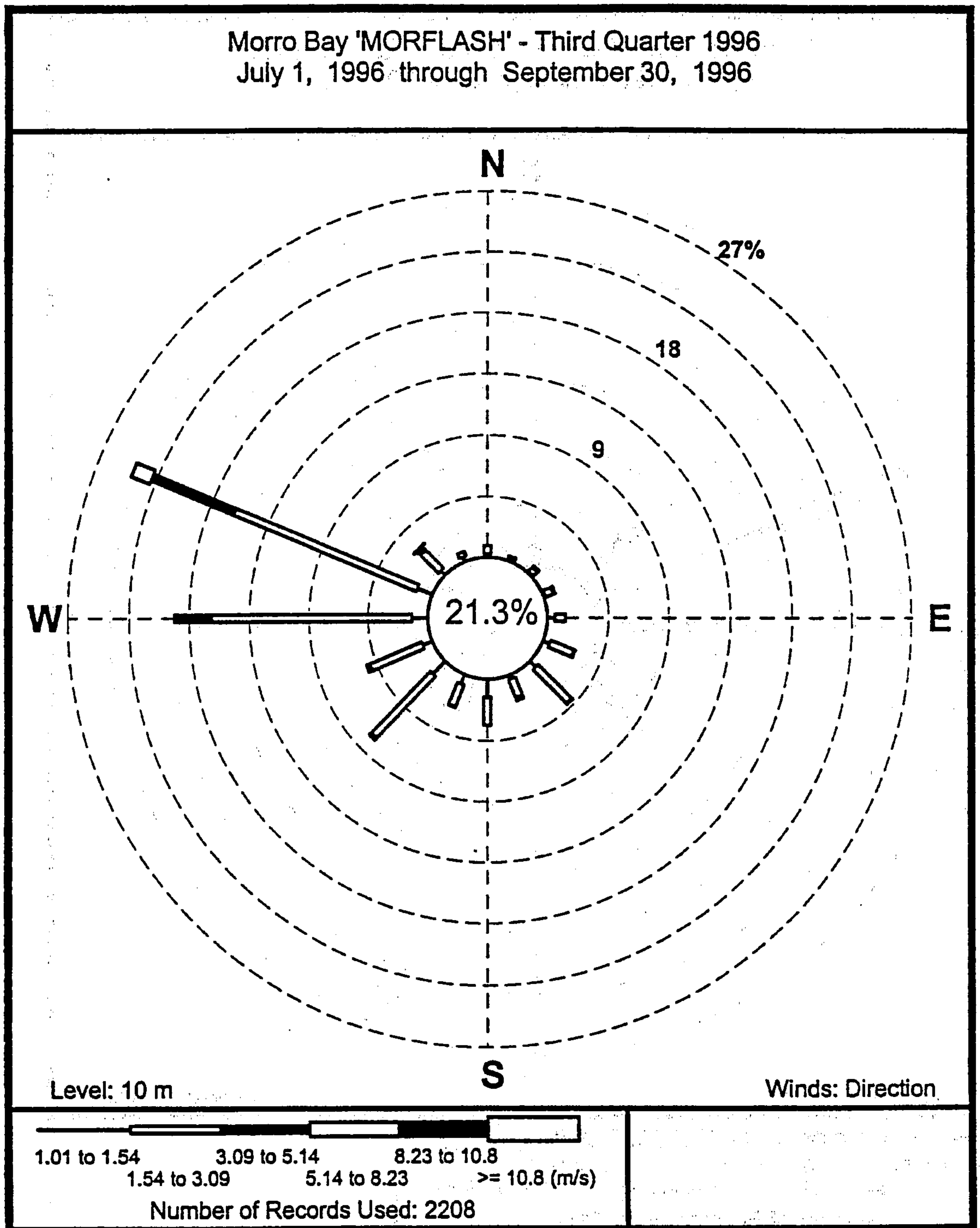
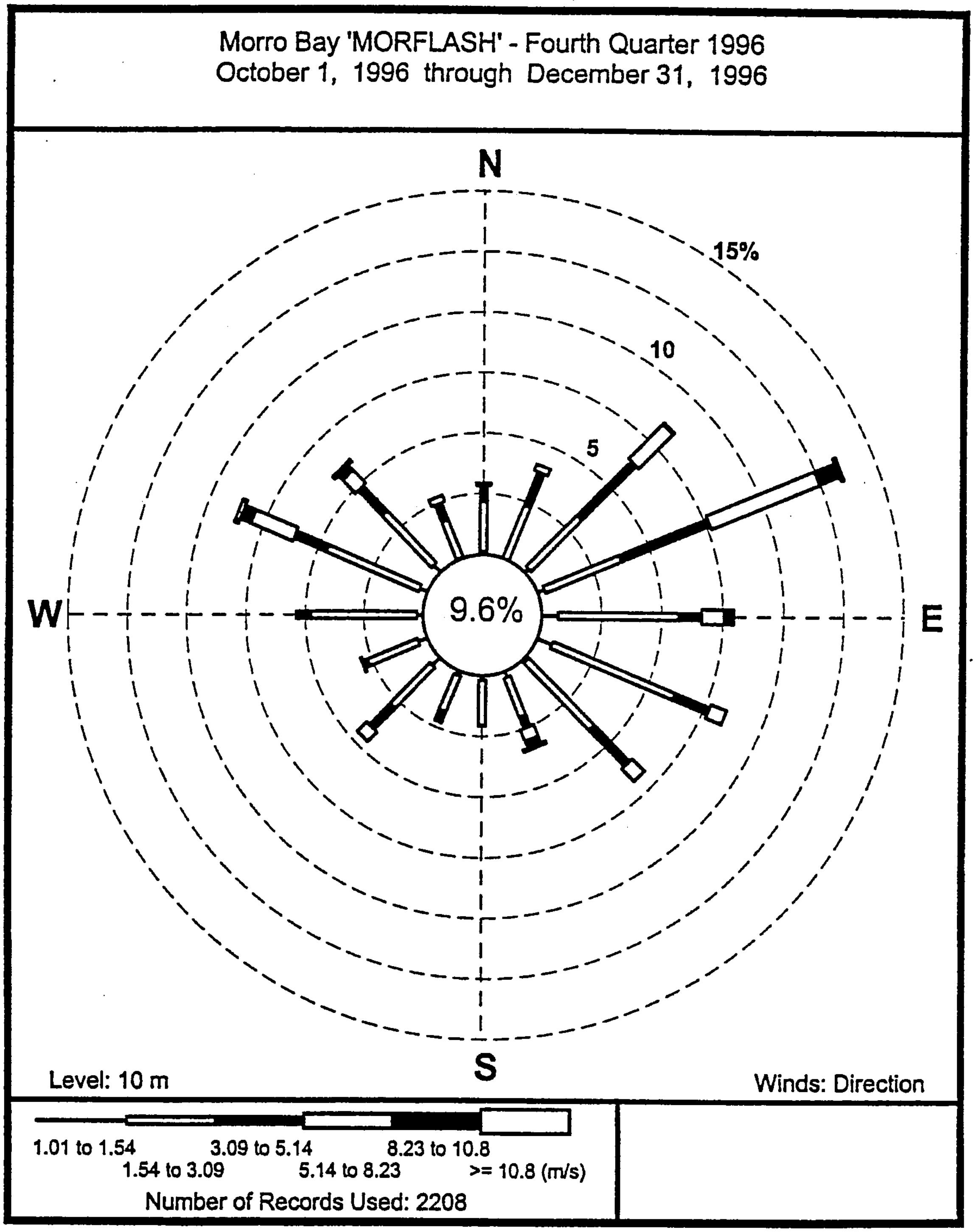

Morro Bay 'MORFLASH' - Third Quarter 1996
July 1, 1996 through September 30, 1996
N
27%
18
9
W
21.3%
E
S
Level: 10 m
Winds: Direction
1.01 to 1.54
3.09 to 5.14
8.23 to 10.8
1.54 to 3.09
5.14 to 8.23
>= 10.8 (m/s)
Number of Records Used: 2208

Figure 6.2-7e



Morro Bay 'MORFLASH' - Fourth Quarter 1996
October 1, 1996 through December 31, 1996
N
15%
10
5
W
9.6%
E
S
Level: 10 m
Winds: Direction
1.01 to 1.54
3.09 to 5.14
8.23 to 10.8
1.54 to 3.09
5.14 to 8.23
>= 10.8 (m/s)
Number of Records Used: 2208

Figure 6.2-8a

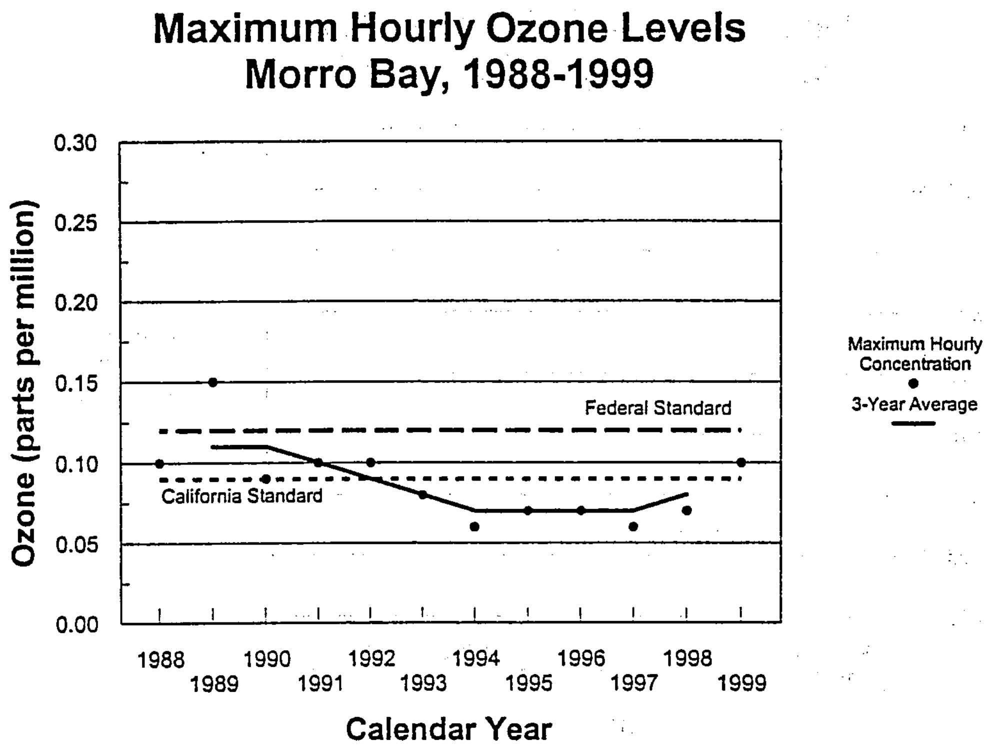


Figure 6.2-8b

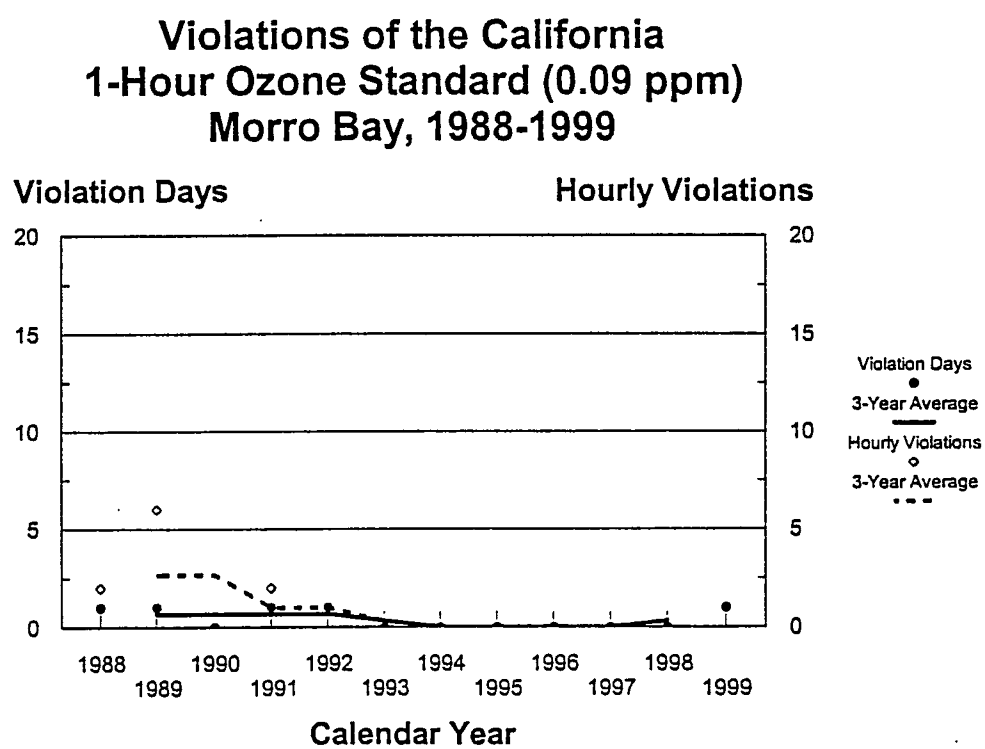


Figure 6.2-9

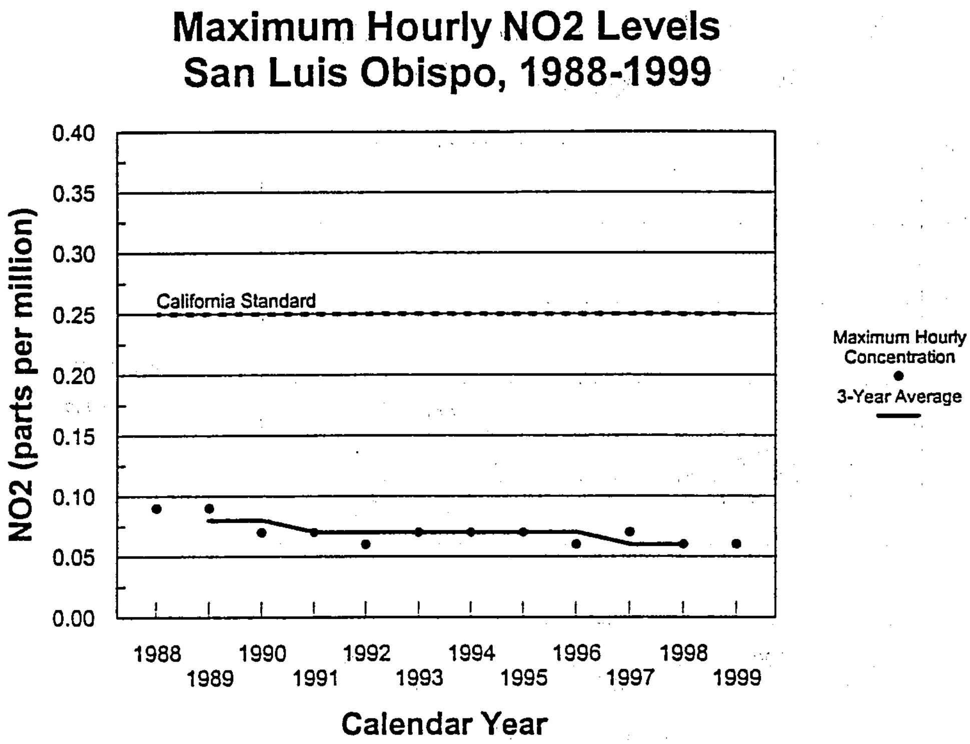

Maximum Hourly NO2 Levels
San Luis Obispo, 1988-1999
0.40
0.35
0.30
0.25
0.20
0.15
0.10
0.05
0.00
NO2 (parts per million)
California Standard
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
Calendar Year
Maximum Hourly Concentration
3-Year Average

Figure 6.2-10

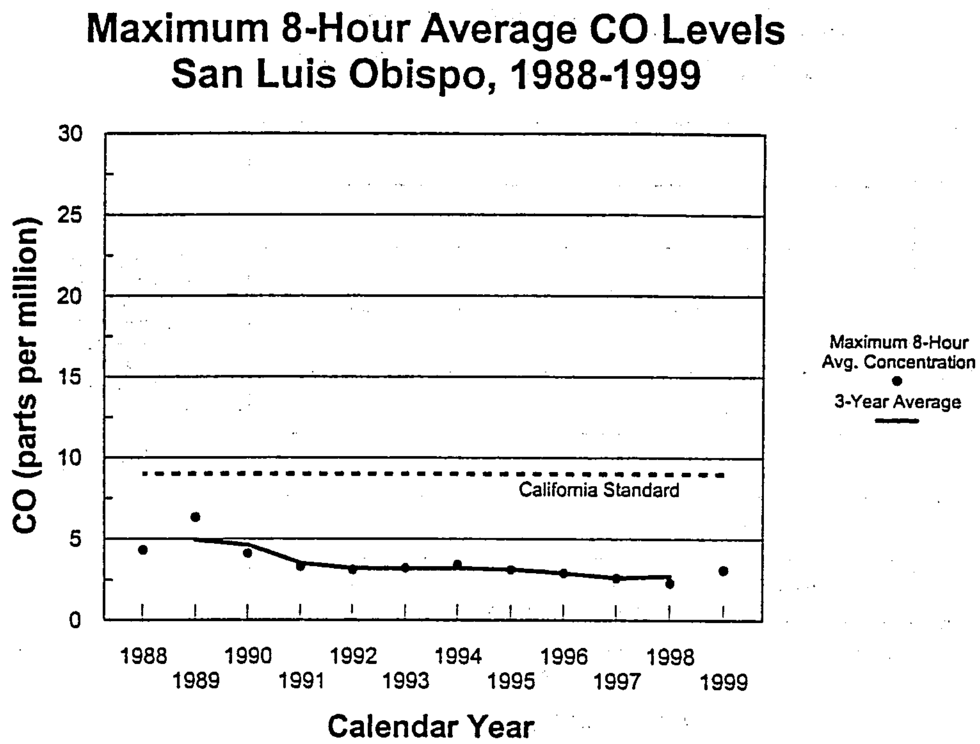


Figure 6.2-11

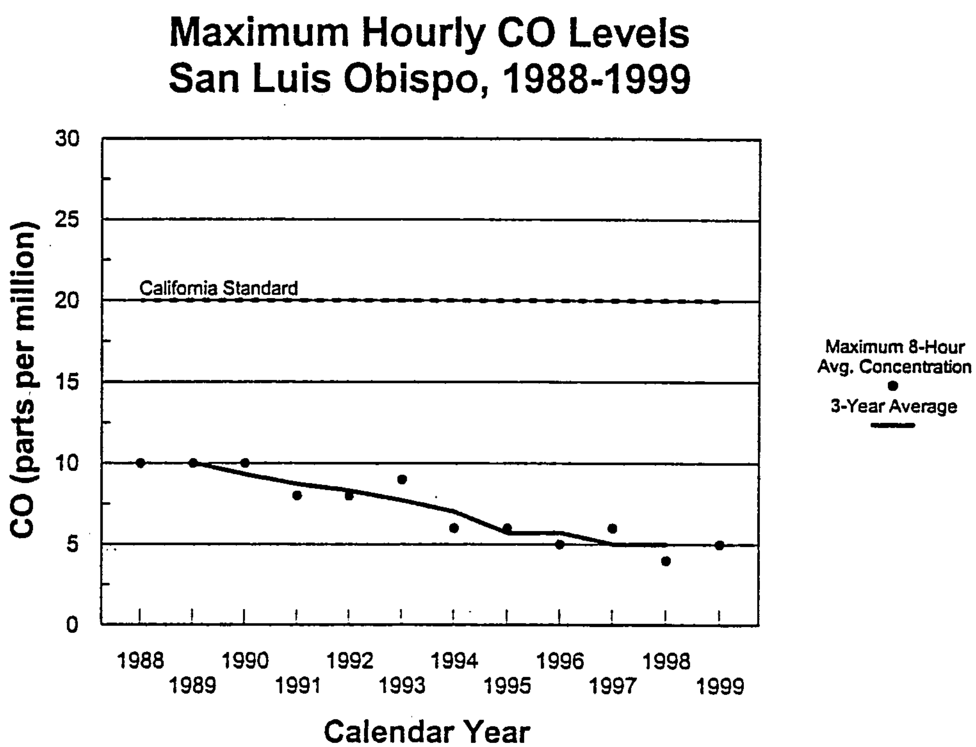
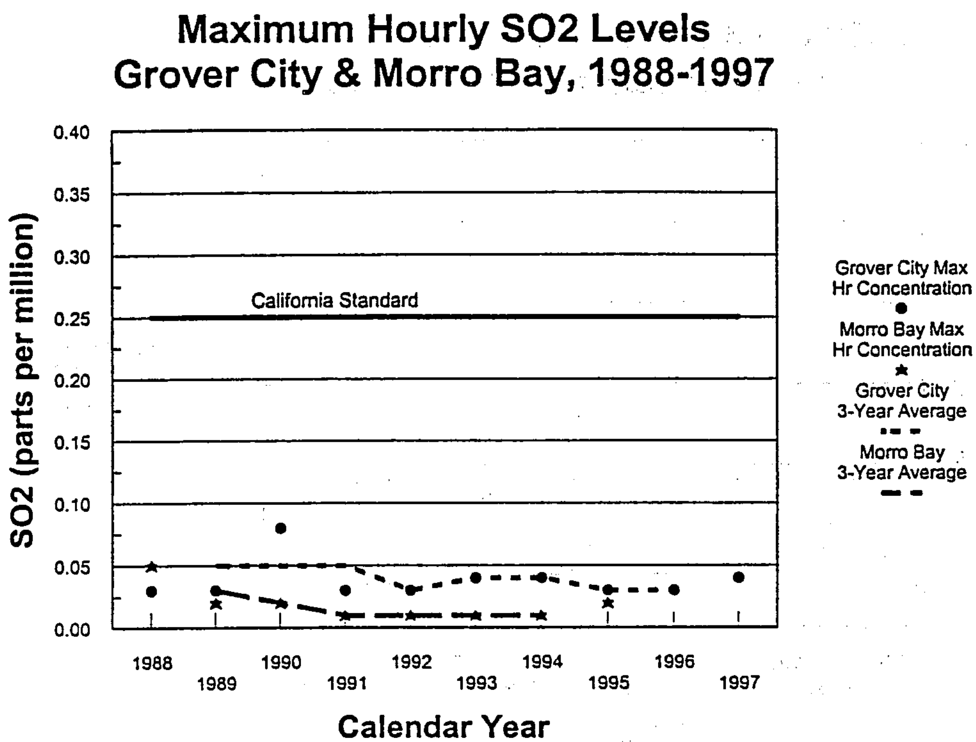


Figure 6.2-12



Maximum Hourly SO2 Levels
Grover City & Morro Bay, 1988-1997
0.40
0.35
0.30
0.25
0.20
0.15
0.10
0.05
0.00
SO2 (parts per million)
California Standard
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
Calendar Year
Grover City Max Hr Concentration
Morro Bay Max Hr Concentration
Grover City 3-Year Average
Morro Bay 3-Year Average

Figure 6.2-13

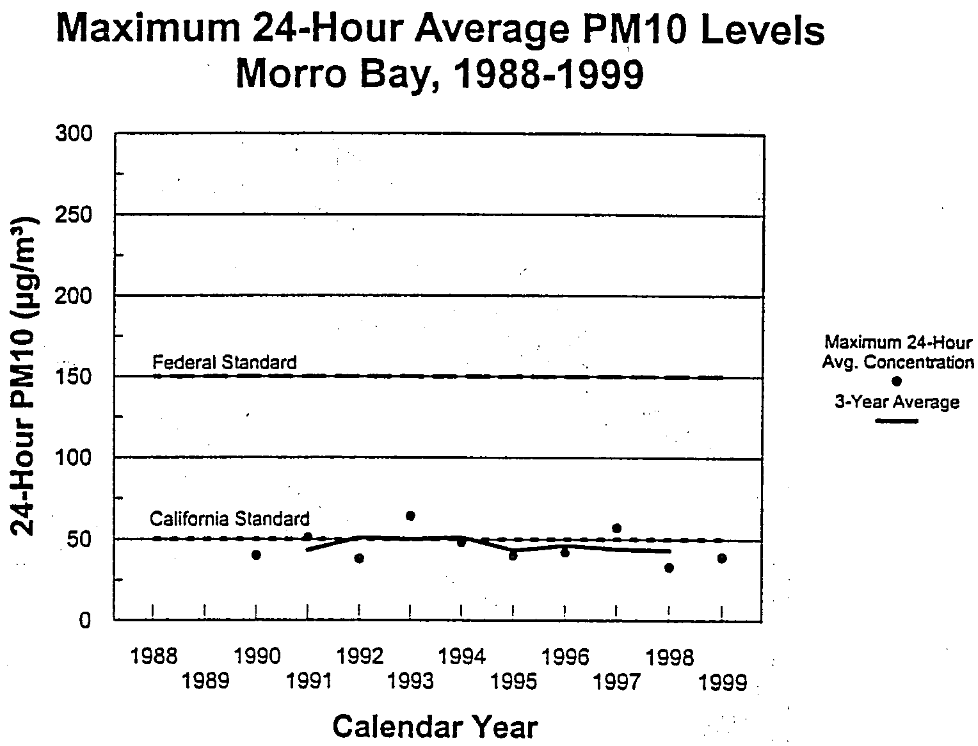


Figure 6.2-14

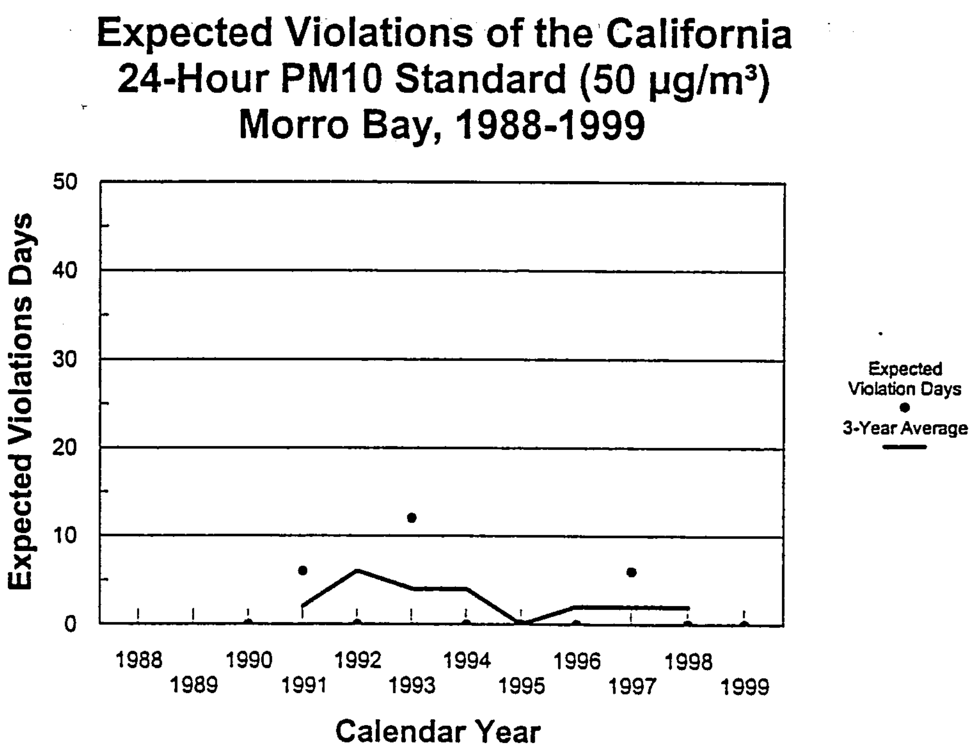
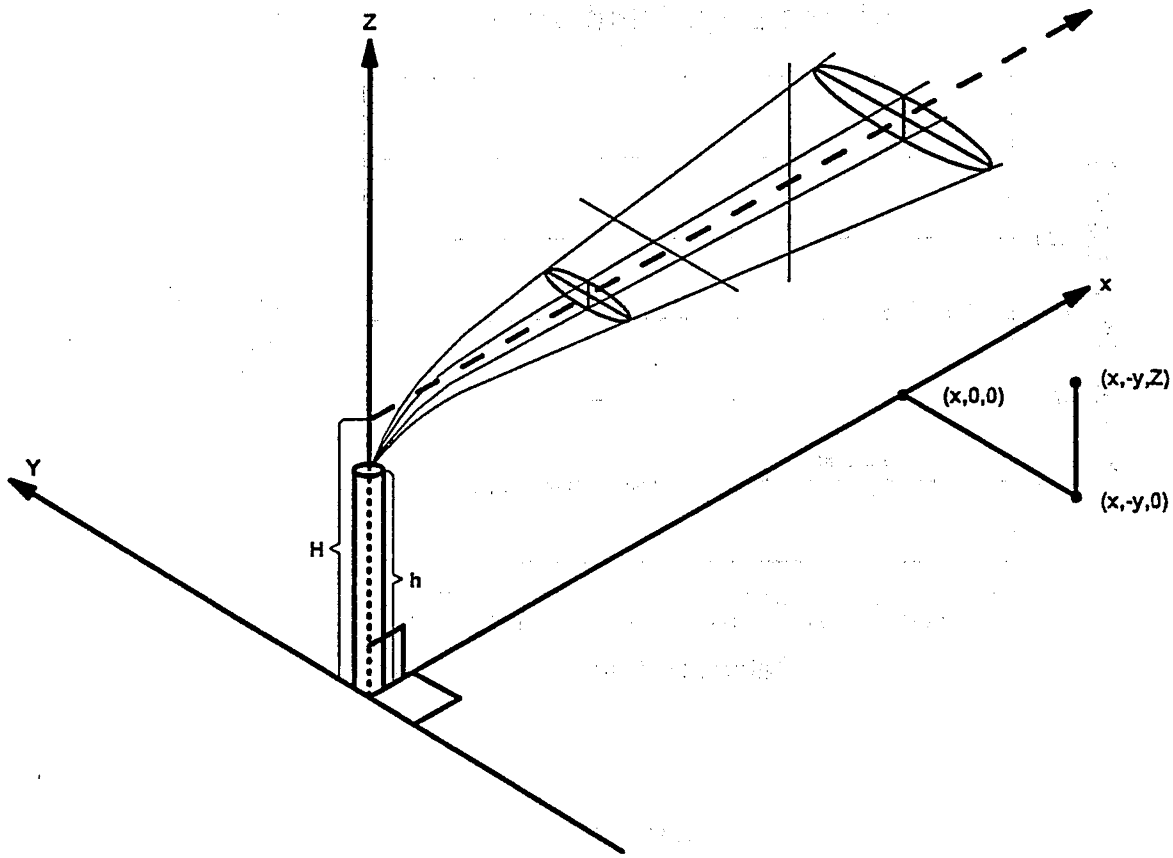
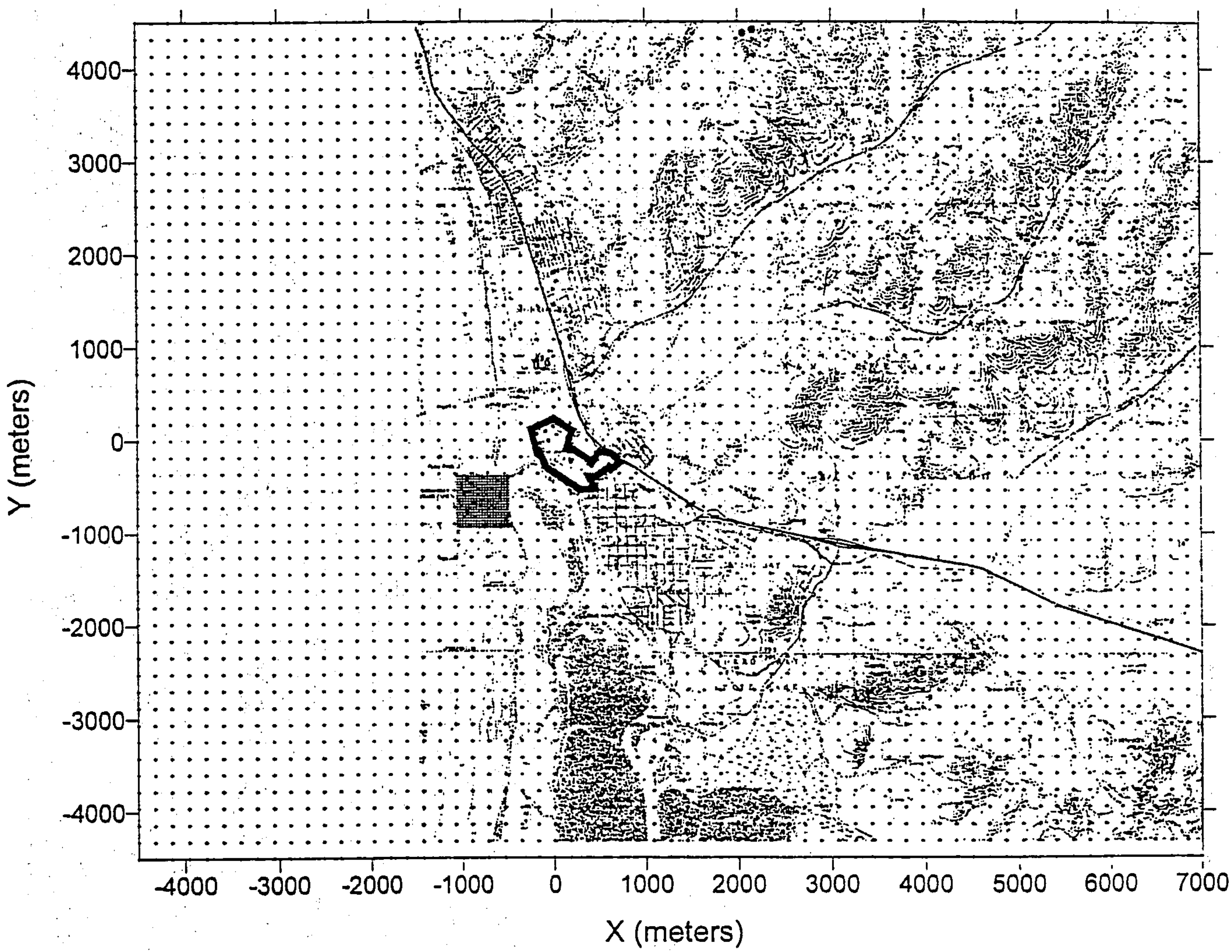


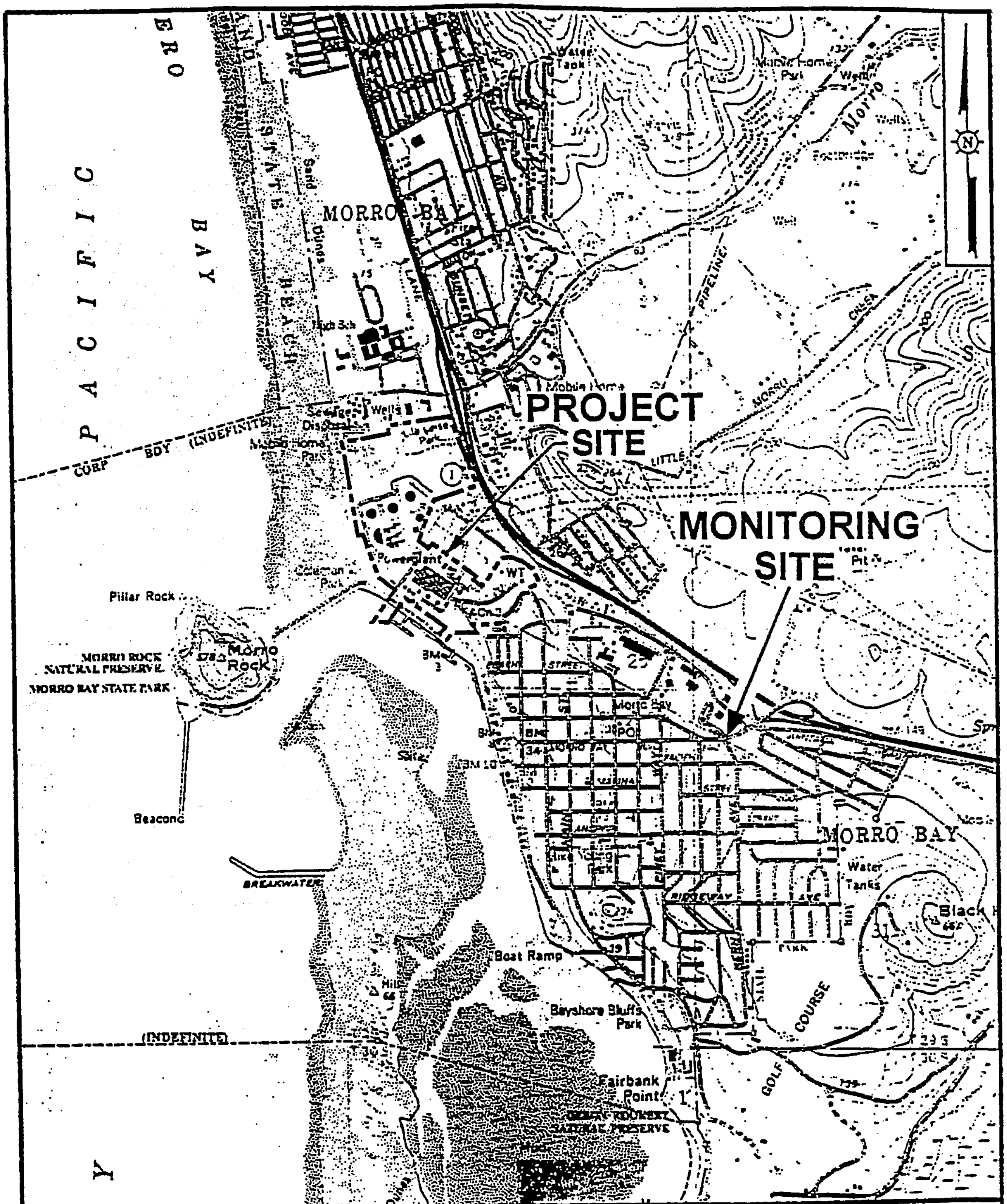
Figure 6.2-15



Coordinate system showing Gaussian distributions in the horizontal and vertical.

Figure 6.2-16
Layout of the Receptor Grid





0 2,000 4,000 FEET

SCALE

SCALE: 1: 24,000

REFERENCE: USGS 7.5 MINUTE TOPOGRAPHIC MAP OF MORRO BAY NORTH AND MORRO BAY SOUTH, CALIFORNIA, DATED 1993 AND 1994.

LOCATION OF PM_{10} MONITORING STATION

FIGURE 6.2-17

APPENDIX 6.2

AIR QUALITY

APPENDIX 6.2-1
DETAILED EMISSIONS CALCULATIONS

ATTACHMENT 6.2-1.1

CALCULATION OF BASELINE EMISSIONS AND ERCS

DUKE ENERGY POWER SERVICES
MORRO BAY POWER PLANT

MONTHLY EMISSIONS - UNIT 1

Year	Month	Natural Gas Consumption (EBs)	Gross Power Generation (MW-hr)	Emissions (tons)					
				CO	NOx	BARCT NOx	PM	SOx	VOC
1997	January	-	-	-	-	-	-	-	-
	February	-	-	-	-	-	-	-	-
	March	-	-	-	-	-	-	-	-
	April	6,766	3,734	-	2.231	0.768	0.157	0.012	0.113
	May	40,370	24,575	5.219	13.654	4.579	0.935	0.074	0.677
	June	10,899	6,613	0.405	3.257	1.236	0.253	0.020	0.183
	July	10,895	6,423	0.400	3.132	1.236	0.252	0.020	0.183
	August	12,373	7,262	0.608	3.226	1.404	0.287	0.023	0.207
	September	37,695	22,256	1.005	11.385	4.276	0.873	0.069	0.632
	October	19,768	11,755	0.480	5.908	2.242	0.458	0.036	0.331
	November	5,735	3,385	1.501	1.667	0.651	0.133	0.010	0.096
	December	-	-	-	-	-	-	-	-
1998	January	-	-	-	-	-	-	-	-
	February	-	-	-	-	-	-	-	-
	March	-	-	-	-	-	-	-	-
	April	-	-	-	-	-	-	-	-
	May	-	-	-	-	-	-	-	-
	June	-	-	-	-	-	-	-	-
	July	50,244	30,853	7.604	15.848	5.700	1.164	0.092	0.843
	August	115,760	71,336	38.373	34.585	13.132	2.682	0.212	1.941
	September	52,400	31,960	5.607	13.410	5.944	1.214	0.096	0.879
	October	35,820	21,941	1.278	11.483	4.063	0.830	0.066	0.601
	November	24,305	15,072	5.116	6.706	2.757	0.563	0.044	0.408
	December	12,835	7,971	2.634	3.351	1.456	0.297	0.023	0.215
1999	January	-	-	-	-	-	-	-	-
	February	-	-	-	-	-	-	-	-
	March	1,796	1,001	0.132	0.692	0.204	0.042	0.003	0.030
	April	5,736	3,436	0.399	1.497	0.651	0.133	0.010	0.096
	May	29,389	18,142	1.083	6.932	3.334	0.681	0.054	0.493
	June	44,195	27,034	1.592	11.792	5.013	1.024	0.081	0.741
	July	92,720	56,955	2.703	21.678	10.518	2.148	0.170	1.555
	August	32,200	19,483	0.889	6.613	3.653	0.746	0.059	0.540
	September	54,575	33,529	9.242	17.073	6.191	1.265	0.100	0.915
	October	122,917	76,423	25.121	45.628	13.943	2.848	0.225	2.061
	November	46,832	28,834	7.509	17.222	5.313	1.085	0.086	0.785
	December	-	-	-	-	-	-	-	-
2000	January	94,032	58,915	2.882	33.099	10.667	2.179	0.172	1.577
	February	94,277	58,510	2.778	26.729	10.695	2.184	0.172	1.581
	March	-	-	-	-	-	-	-	-
	April	-	-	-	-	-	-	-	-
	May	89,236	55,677	13.969	31.388	10.123	2.068	0.163	1.496
	June	137,613	85,860	13.419	48.195	15.610	3.189	0.252	2.308
	July	137,910	86,152	25.346	48.464	15.644	3.195	0.252	2.313
	August	-	-	-	-	-	-	-	-
	September	-	-	-	-	-	-	-	-
	October	-	-	-	-	-	-	-	-
	November	-	-	-	-	-	-	-	-
	December	-	-	-	-	-	-	-	-

36-MONTH AVERAGE EMISSIONS - UNIT 1

Year Ending	Month Ending	Natural Gas Consumption (EBs)	Gross Power Generation (MW-hr)	Emissions (tons)					
				CO	NOx	BARCT NOx	PM	SOx	VOC
1999	December	288,742	176,658	39.6	86.3	32.8	6.69	0.53	4.84
2000	January	320,086	196,296	40.6	97.4	36.3	7.42	0.59	5.37
	February	351,512	215,800	41.5	106	39.9	8.14	0.64	5.89
	March	351,512	215,800	41.5	106	39.9	8.14	0.64	5.89
	April	349,256	214,555	41.5	106	39.6	8.09	0.64	5.86
	May	365,545	224,922	44.4	111	41.5	8.47	0.67	6.13
	June	407,783	251,338	48.8	126	46.3	9.45	0.75	6.84
	July	450,121	277,914	57.1	142	51.1	10.43	0.82	7.55
	August								
	September								
	October								
	November								
	December								

24-MONTH AVERAGE EMISSIONS - UNIT 1

Year Ending	Month Ending	Natural Gas Consumption (EBs)	Gross Power Generation (MW-hr)	Emissions (tons)					
				CO	NOx	BARCT NOx	PM	SOx	VOC
1998	December	217,933	132,568	35.1	64.9	24.7	5.05	0.40	3.65
1999	January	217,933	132,568	35.1	64.9	24.7	5.05	0.40	3.65
	February	217,933	132,568	35.1	64.9	24.7	5.05	0.40	3.65
	March	218,831	133,069	35.2	65.3	24.8	5.07	0.40	3.67
	April	218,316	132,919	35.4	64.9	24.8	5.06	0.40	3.66
	May	212,826	129,703	33.3	61.5	24.1	4.93	0.39	3.57
	June	229,473	139,914	33.9	65.8	26.0	5.32	0.42	3.85
	July	270,386	165,180	35.1	75.1	30.7	6.27	0.49	4.53
	August	280,299	171,290	35.2	76.8	31.8	6.49	0.51	4.70
	September	288,739	176,927	39.3	79.6	32.8	6.69	0.53	4.84
	October	340,314	209,260	51.6	99.5	38.6	7.89	0.62	5.71
	November	360,862	221,985	54.6	107	40.9	8.36	0.66	6.05
	December	360,862	221,985	54.6	107	40.9	8.36	0.66	6.05
2000	January	407,878	251,443	56.1	124	46.3	9.45	0.75	6.84
	February	455,017	280,698	57.5	137	51.6	10.5	0.83	7.63
	March	455,017	280,698	57.5	137	51.6	10.5	0.83	7.63
	April	455,017	280,698	57.5	137	51.6	10.5	0.83	7.63
	May	499,635	308,536	64.5	153	56.7	11.6	0.91	8.38
	June	568,441	351,466	71.2	177	64.5	13.2	1.04	9.53
	July	612,274	379,116	80.0	193	69.5	14.2	1.12	10.3
	August								
	September								
	October								
	November								
	December								

DUKE ENERGY POWER SERVICES
MORRO BAY POWER PLANT

MONTHLY EMISSIONS - UNIT 2

Year	Month	Natural Gas Consumption (EBs)	Gross Power Generation (MW-hr)	Emissions (tons)					
				CO	NOx	BARCT NOx	PM	SOx	VOC
1997	January	-	-	-	-	-	-	-	-
	February	-	-	-	-	-	-	-	-
	March	-	-	-	-	-	-	-	-
	April	13	-	-	0.001	0.001	0.000	0.000	0.000
	May	36,157	21,832	0.428	14.171	4.102	0.838	0.066	0.606
	June	-	-	-	-	-	-	-	-
	July	-	-	-	-	-	-	-	-
	August	8,193	4,669	0.013	2.570	0.929	0.190	0.015	0.137
	September	43,902	25,870	2.140	15.685	4.980	1.017	0.080	0.736
	October	17,032	10,158	0.443	6.309	1.932	0.395	0.031	0.286
	November	5,587	3,311	1.304	1.762	0.634	0.129	0.010	0.094
	December	-	-	-	-	-	-	-	-
1998	January	11,476	6,666	0.219	3.451	1.302	0.266	0.021	0.192
	February	-	-	-	-	-	-	-	-
	March	-	-	-	-	-	-	-	-
	April	-	-	-	-	-	-	-	-
	May	-	-	-	-	-	-	-	-
	June	-	-	-	-	-	-	-	-
	July	46,113	27,876	2.756	17.541	5.231	1.068	0.084	0.773
	August	119,806	73,029	1.581	44.757	13.590	2.776	0.219	2.009
	September	50,551	30,299	0.189	15.252	5.734	1.171	0.092	0.848
	October	39,611	23,955	0.189	13.436	4.493	0.918	0.072	0.664
	November	3,374	2,031	0.750	1.012	0.383	0.078	0.006	0.057
	December	14,784	8,968	3.002	5.307	1.677	0.343	0.027	0.248
1999	January	-	-	-	-	-	-	-	-
	February	-	-	-	-	-	-	-	-
	March	-	-	-	-	-	-	-	-
	April	6,828	3,915	0.477	2.697	0.775	0.158	0.012	0.114
	May	39,069	23,704	0.490	12.331	4.432	0.905	0.071	0.655
	June	48,985	29,328	0.091	16.211	5.557	1.135	0.090	0.821
	July	93,194	56,360	0.772	29.394	10.572	2.159	0.170	1.563
	August	74,451	44,499	0.172	24.542	8.446	1.725	0.136	1.248
	September	87,158	52,151	1.827	26.526	9.887	2.020	0.159	1.461
	October	137,649	83,757	4.475	52.202	15.615	3.189	0.252	2.308
	November	81,070	49,075	14.254	32.316	9.196	1.878	0.148	1.359
	December	108,932	69,742	18.758	49.030	12.357	2.524	0.199	1.827
2000	January	133,568	81,792	0.489	53.330	15.152	3.095	0.244	2.240
	February	70,473	42,717	0.082	25.738	7.994	1.633	0.129	1.182
	March	-	-	-	-	-	-	-	-
	April	3,947	2,208	-	1.305	0.448	0.091	0.007	0.066
	May	82,644	51,057	0.245	33.595	9.375	1.915	0.151	1.386
	June	135,393	83,555	0.135	56.916	15.359	3.137	0.248	2.270
	July	122,023	75,603	1.565	51.130	13.842	2.827	0.223	2.046
	August	-	-	-	-	-	-	-	-
	September	-	-	-	-	-	-	-	-
	October	-	-	-	-	-	-	-	-
	November	-	-	-	-	-	-	-	-
	December	-	-	-	-	-	-	-	-

36-MONTH AVERAGE EMISSIONS - UNIT 2

Year Ending	Month Ending	Natural Gas Consumption (EBs)	Gross Power Generation (MW-hr)	Emissions (tons)					
				CO	NOx	BARCT NOx	PM	SOx	VOC
1999	December	357,978	217,065	18.1	129	40.6	8.29	0.65	6.00
2000	January	402,501	244,329	18.3	147	45.7	9.33	0.74	6.75
	February	425,992	258,568	18.3	155	48.3	9.87	0.78	7.14
	March	425,992	258,568	18.3	155	48.3	9.87	0.78	7.14
	April	427,303	259,304	18.3	156	48.5	9.90	0.78	7.17
	May	442,799	269,046	18.2	162	50.2	10.26	0.81	7.42
	June	487,930	296,897	18.3	181	55.3	11.31	0.89	8.18
	July	528,604	322,098	18.8	198	60.0	12.25	0.97	8.86
	August								
	September								
	October								
	November								
	December								

24-MONTH AVERAGE EMISSIONS - UNIT 2

Year Ending	Month Ending	Natural Gas Consumption (EBs)	Gross Power Generation (MW-hr)	Emissions (tons)					
				CO	NOx	BARCT NOx	PM	SOx	VOC
1998	December	198,299	119,332	6.51	70.6	22.5	4.59	0.36	3.33
1999	January	198,299	119,332	6.51	70.6	22.5	4.59	0.36	3.33
	February	198,299	119,332	6.51	70.6	22.5	4.59	0.36	3.33
	March	198,299	119,332	6.51	70.6	22.5	4.59	0.36	3.33
	April	201,707	121,289	6.75	72.0	22.9	4.67	0.37	3.38
	May	203,163	122,225	6.78	71.1	23.0	4.71	0.37	3.41
	June	227,655	136,889	6.82	79.2	25.8	5.27	0.42	3.82
	July	274,252	165,069	7.21	93.9	31.1	6.35	0.50	4.60
	August	307,381	184,984	7.29	105	34.9	7.12	0.56	5.15
	September	329,009	198,125	7.13	110	37.3	7.62	0.60	5.52
	October	389,318	234,924	9.15	133	44.2	9.02	0.71	6.53
	November	427,060	257,806	15.6	148	48.4	9.90	0.78	7.16
	December	481,526	292,677	25.0	173	54.6	11.2	0.88	8.07
2000	January	542,571	330,240	25.1	198	61.5	12.6	0.99	9.10
	February	577,808	351,599	25.2	211	65.5	13.4	1.06	9.69
	March	577,808	351,599	25.2	211	65.5	13.4	1.06	9.69
	April	579,781	352,703	25.2	211	65.8	13.4	1.06	9.72
	May	621,103	378,231	25.3	228	70.5	14.4	1.14	10.4
	June	688,800	420,009	25.4	257	78.1	16.0	1.26	11.5
	July	726,755	443,872	24.8	274	82.4	16.8	1.33	12.2
	August								
	September								
	October								
	November								
	December								

DUKE ENERGY POWER SERVICES
MORRO BAY POWER PLANT

MONTHLY EMISSIONS - UNIT 3

Year	Month	Natural Gas Consumption (EBs)	Gross Power Generation (MW-hr)	Emissions (tons)					
				CO	NOx	BARCT NOx	PM	SOx	VOC
1997	January	90,108	54,799	25.098	6.665	3.407	2.088	0.165	1.511
	February	82,018	50,355	15.581	6.609	3.101	1.900	0.150	1.375
	March	47,751	30,313	13.113	4.627	1.806	1.106	0.087	0.801
	April	169,326	112,215	59.783	15.325	6.403	3.923	0.310	2.839
	May	189,310	125,985	82.239	20.230	7.158	4.386	0.346	3.174
	June	75,657	47,438	19.124	6.859	2.861	1.753	0.138	1.269
	July	118,932	77,998	44.144	11.368	4.497	2.756	0.218	1.994
	August	96,788	62,260	39.149	8.546	3.660	2.243	0.177	1.623
	September	139,549	91,501	64.348	14.496	5.277	3.233	0.255	2.340
	October	157,768	101,492	45.637	14.237	5.966	3.656	0.289	2.645
	November	105,048	68,348	6.682	7.487	3.972	2.434	0.192	1.761
	December	120,860	77,662	8.721	10.847	4.570	2.800	0.221	2.027
1998	January	74,138	48,126	36.712	4.410	2.803	1.718	0.136	1.243
	February	19,374	12,178	5.611	1.439	0.733	0.449	0.035	0.325
	March	7,165	4,451	2.939	0.761	0.271	0.166	0.013	0.120
	April	93,662	60,286	28.729	8.169	3.542	2.170	0.171	1.571
	May	76,676	43,972	5.764	7.666	2.899	1.777	0.140	1.286
	June	127,430	80,983	22.781	11.325	4.818	2.953	0.233	2.137
	July	139,190	90,761	61.880	14.828	5.263	3.225	0.255	2.334
	August	234,372	154,415	143.273	29.051	8.862	5.431	0.429	3.930
	September	166,573	107,801	56.783	14.306	6.299	3.860	0.305	2.793
	October	115,848	76,344	40.278	8.603	4.381	2.684	0.212	1.943
	November	159,416	104,196	9.653	9.653	6.028	3.694	0.292	2.673
	December	161,988	105,685	9.361	9.470	6.125	3.753	0.296	2.716
1999	January	165,439	107,832	38.045	11.459	6.256	3.833	0.303	2.774
	February	147,817	96,121	39.195	9.881	5.589	3.425	0.270	2.479
	March	119,916	77,590	30.827	7.328	4.534	2.779	0.219	2.011
	April	33,643	21,482	10.283	2.013	1.272	0.780	0.062	0.564
	May	117,053	76,207	30.807	6.744	4.426	2.712	0.214	1.963
	June	171,683	112,944	53.320	10.148	6.492	3.978	0.314	2.879
	July	182,029	119,266	65.304	13.133	6.883	4.218	0.333	3.052
	August	121,823	79,805	40.380	7.789	4.606	2.823	0.223	2.043
	September	175,454	114,831	69.799	10.577	6.634	4.065	0.321	2.942
	October	200,502	132,851	80.178	17.615	7.581	4.646	0.367	3.362
	November	243,459	162,030	14.626	26.614	9.206	5.641	0.445	4.082
	December	174,408	115,126	12.092	17.619	6.595	4.041	0.319	2.925
2000	January	241,068	160,678	89.796	26.106	9.115	5.586	0.441	4.042
	February	220,233	146,378	63.451	18.306	8.328	5.103	0.403	3.693
	March	189,553	124,457	44.362	14.834	7.167	4.392	0.347	3.178
	April	112,760	73,693	39.539	8.564	4.264	2.613	0.206	1.891
	May	81,360	53,808	47.915	9.285	3.076	1.885	0.149	1.364
	June	275,482	183,433	157.063	31.590	10.417	6.383	0.504	4.619
	July	235,295	156,150	103.146	21.089	8.897	5.452	0.430	3.945
	August	-	-	-	-	-	-	-	-
	September	-	-	-	-	-	-	-	-
	October	-	-	-	-	-	-	-	-
	November	-	-	-	-	-	-	-	-
	December	-	-	-	-	-	-	-	-

36-MONTH AVERAGE EMISSIONS - UNIT 3

Year Ending	Month Ending	Natural Gas Consumption (EBs)	Gross Power Generation (MW-hr)	Emissions (tons)					
				CO	NOx	BARCT NOx	PM	SOx	VOC
1999	December	1,540,724	1,001,883	444	129	58.3	35.7	2.82	25.8
2000	January	1,591,045	1,037,176	466	136	60.2	36.9	2.91	26.7
	February	1,637,116	1,069,183	482	140	61.9	37.9	2.99	27.5
	March	1,684,384	1,100,565	492	143	63.7	39.0	3.08	28.2
	April	1,665,528	1,087,724	485	141	63.0	38.6	3.05	27.9
	May	1,629,545	1,063,665	474	137	61.6	37.8	2.98	27.3
	June	1,696,153	1,108,997	520	145	64.1	39.3	3.10	28.4
	July	1,734,941	1,135,047	539	149	65.6	40.2	3.17	29.1
	August								
	September								
	October								
	November								
	December								

24-MONTH AVERAGE EMISSIONS - UNIT 3

Year Ending	Month Ending	Natural Gas Consumption (EBs)	Gross Power Generation (MW-hr)	Emissions (tons)					
				CO	NOx	BARCT NOx	PM	SOx	VOC
1998	December	1,384,474	894,782	424	123	52.4	32.1	2.53	23.2
1999	January	1,422,139	921,299	430	126	53.8	33.0	2.60	23.8
	February	1,455,039	944,182	442	128	55.0	33.7	2.66	24.4
	March	1,491,121	967,820	451	129	56.4	34.6	2.73	25.0
	April	1,423,280	922,454	426	122	53.8	33.0	2.60	23.9
	May	1,387,151	897,565	400	115	52.5	32.1	2.54	23.3
	June	1,435,164	930,318	417	117	54.3	33.3	2.63	24.1
	July	1,466,713	950,952	428	118	55.5	34.0	2.68	24.6
	August	1,479,230	959,724	429	118	55.9	34.3	2.71	24.8
	September	1,497,183	971,389	431	116	56.6	34.7	2.74	25.1
	October	1,518,550	987,069	449	117	57.4	35.2	2.78	25.5
	November	1,587,755	1,033,909	453	127	60.0	36.8	2.90	26.6
	December	1,614,529	1,052,641	454	130	61.0	37.4	2.95	27.1
2000	January	1,697,994	1,108,917	481	141	64.2	39.3	3.11	28.5
	February	1,798,424	1,176,017	510	150	68.0	41.7	3.29	30.2
	March	1,889,618	1,236,020	530	157	71.5	43.8	3.46	31.7
	April	1,899,167	1,242,723	536	157	71.8	44.0	3.47	31.8
	May	1,901,509	1,247,642	557	158	71.9	44.1	3.48	31.9
	June	1,975,535	1,298,867	624	168	74.7	45.8	3.61	33.1
	July	2,023,587	1,331,561	645	171	76.5	46.9	3.70	33.9
	August								
	September								
	October								
	November								
	December								

DUKE ENERGY POWER SERVICES
MORRO BAY POWER PLANT

MONTHLY EMISSIONS - UNIT 4

Year	Month	Natural Gas Consumption (EBs)	Gross Power Generation (MW-hr)	Emissions (tons)					
				CO	NOx	BARCT NOx	PM	SOx	VOC
1997	January	-	-	-	-	-	-	-	-
	February	-	-	-	-	-	-	-	-
	March	50,196	30,349	4.340	3.168	1.898	1.163	0.092	0.842
	April	88,521	57,674	14.273	8.966	3.347	2.051	0.162	1.484
	May	90,679	60,171	22.146	12.038	3.429	2.101	0.166	1.521
	June	67,730	42,564	12.640	6.479	2.561	1.569	0.124	1.136
	July	124,252	80,423	28.282	13.252	4.698	2.879	0.227	2.083
	August	162,332	104,953	33.165	18.273	6.138	3.761	0.297	2.722
	September	190,210	124,393	45.706	22.798	7.192	4.407	0.348	3.189
	October	20,165	13,113	4.626	2.557	0.762	0.467	0.037	0.338
	November	136,721	90,048	10.923	13.613	5.170	3.168	0.250	2.293
	December	46,448	28,026	3.431	3.926	1.756	1.076	0.085	0.779
1998	January	111,121	70,677	26.993	10.284	4.202	2.575	0.203	1.863
	February	14,605	8,288	3.320	0.955	0.552	0.338	0.027	0.245
	March	126,952	80,028	17.331	12.704	4.800	2.942	0.232	2.129
	April	105,014	65,182	14.572	9.394	3.971	2.433	0.192	1.761
	May	76,161	42,731	7.467	6.011	2.880	1.765	0.139	1.277
	June	112,428	70,039	13.781	10.484	4.251	2.605	0.206	1.885
	July	122,660	78,995	43.404	13.206	4.638	2.842	0.224	2.057
	August	235,556	153,943	113.112	27.421	8.907	5.458	0.431	3.950
	September	166,921	106,835	40.931	15.338	6.312	3.868	0.305	2.799
	October	210,253	136,870	73.430	21.215	7.950	4.872	0.385	3.526
	November	164,454	105,566	12.353	12.742	6.218	3.811	0.301	2.758
	December	143,605	92,800	11.487	12.104	5.430	3.327	0.263	2.408
1999	January	136,245	87,478	17.938	11.674	5.152	3.157	0.249	2.285
	February	150,111	96,698	24.727	11.200	5.676	3.478	0.275	2.517
	March	139,848	90,052	34.734	10.585	5.288	3.240	0.256	2.345
	April	180,715	117,516	35.868	14.238	6.833	4.187	0.331	3.030
	May	109,042	70,521	19.316	8.789	4.123	2.527	0.199	1.828
	June	127,155	82,567	26.100	11.084	4.808	2.946	0.233	2.132
	July	71,361	45,705	20.169	6.910	2.698	1.653	0.131	1.197
	August	170,809	110,200	36.194	14.445	6.459	3.958	0.312	2.864
	September	173,369	111,137	52.112	16.560	6.556	4.017	0.317	2.907
	October	218,325	140,606	96.819	23.418	8.255	5.059	0.399	3.661
	November	222,813	145,111	14.389	26.200	8.425	5.163	0.408	3.736
	December	234,739	153,440	15.474	25.372	8.876	5.439	0.429	3.936
2000	January	241,562	158,856	77.331	26.867	9.134	5.597	0.442	4.051
	February	198,628	130,407	89.935	17.915	7.511	4.602	0.363	3.331
	March	157,367	102,855	42.902	17.496	5.950	3.646	0.288	2.639
	April	47,316	31,103	10.003	5.540	1.789	1.096	0.087	0.793
	May	201,330	132,776	89.181	23.871	7.613	4.665	0.368	3.376
	June	255,907	168,758	166.515	33.241	9.676	5.930	0.468	4.291
	July	297,493	195,926	251.930	41.213	11.249	6.893	0.544	4.988
	August	-	-	-	-	-	-	-	-
	September	-	-	-	-	-	-	-	-
	October	-	-	-	-	-	-	-	-
	November	-	-	-	-	-	-	-	-
	December	-	-	-	-	-	-	-	-

36-MONTH AVERAGE EMISSIONS - UNIT 4

Year Ending	Month Ending	Natural Gas Consumption (EBs)	Gross Power Generation (MW-hr)	Emissions (tons)					
				CO	NOx	BARCT NOx	PM	SOx	VOC
1999	December	1,500,505	964,899	317	146	56.7	34.8	2.74	25.2
2000	January	1,581,026	1,017,851	343	155	59.8	36.6	2.89	26.5
	February	1,647,235	1,061,320	373	161	62.3	38.2	3.01	27.6
	March	1,682,959	1,085,489	386	166	63.6	39.0	3.08	28.2
	April	1,669,224	1,076,632	384	164	63.1	38.7	3.05	28.0
	May	1,706,108	1,100,833	407	168	64.5	39.5	3.12	28.6
	June	1,768,833	1,142,898	458	177	66.9	41.0	3.24	29.7
	July	1,826,580	1,181,399	533	187	69.1	42.3	3.34	30.6
	August								
	September								
	October								
	November								
	December								

24-MONTH AVERAGE EMISSIONS - UNIT 4

Year Ending	Month Ending	Natural Gas Consumption (EBs)	Gross Power Generation (MW-hr)	Emissions (tons)					
				CO	NOx	BARCT NOx	PM	SOx	VOC
1998	December	1,283,492	821,834	279	128	48.5	29.7	2.35	21.5
1999	January	1,351,614	865,573	288	134	51.1	31.3	2.47	22.7
	February	1,426,670	913,922	300	140	53.9	33.1	2.61	23.9
	March	1,471,496	943,773	315	144	55.6	34.1	2.69	24.7
	April	1,517,593	973,694	326	146	57.4	35.2	2.78	25.4
	May	1,526,774	978,869	325	145	57.7	35.4	2.79	25.6
	June	1,556,487	998,871	331	147	58.9	36.1	2.85	26.1
	July	1,530,041	981,511	327	144	57.9	35.5	2.80	25.7
	August	1,534,280	984,135	329	142	58.0	35.6	2.81	25.7
	September	1,525,859	977,507	332	139	57.7	35.4	2.79	25.6
	October	1,624,939	1,041,254	378	149	61.4	37.7	2.97	27.2
	November	1,667,985	1,068,785	380	155	63.1	38.6	3.05	28.0
	December	1,762,131	1,131,492	386	166	66.6	40.8	3.22	29.5
2000	January	1,827,352	1,175,581	411	174	69.1	42.3	3.34	30.6
	February	1,919,363	1,236,640	454	183	72.6	44.5	3.51	32.2
	March	1,934,571	1,248,054	467	185	73.2	44.8	3.54	32.4
	April	1,905,722	1,231,014	465	183	72.1	44.2	3.49	32.0
	May	1,968,306	1,276,037	506	192	74.4	45.6	3.60	33.0
	June	2,040,046	1,325,396	582	204	77.1	47.3	3.73	34.2
	July	2,127,462	1,383,862	686	218	80.4	49.3	3.89	35.7
	August								
	September								
	October								
	November								
	December								

DUKE ENERGY POWER SERVICES
MORRO BAY POWER PLANT

MONTHLY EMISSIONS - COMBINED

Year	Month	Natural Gas Consumption (EBs)	Gross Power Generation (MW-hr)	Emissions (tons)					
				CO	NOx	BARCT NOx	PM	SOx	VOC
1997	January	90,108	54,799	25.098	6.665	3.407	2.088	0.165	1.511
	February	82,018	50,355	15.581	6.609	3.101	1.900	0.150	1.375
	March	97,948	60,662	17.453	7.795	3.704	2.270	0.179	1.642
	April	264,626	173,623	74.056	26.522	10.519	6.132	0.484	4.437
	May	356,516	232,563	110.033	60.093	19.268	8.261	0.652	5.978
	June	154,286	96,615	32.168	16.594	6.658	3.575	0.282	2.587
	July	254,079	164,844	72.826	27.751	10.431	5.887	0.465	4.260
	August	279,686	179,144	72.935	32.616	12.131	6.481	0.512	4.690
	September	411,357	264,020	113.199	64.365	21.725	9.531	0.752	6.898
	October	214,732	136,518	51.185	29.011	10.903	4.975	0.393	3.601
	November	253,091	165,092	20.410	24.528	10.426	5.864	0.463	4.244
	December	167,308	105,688	12.153	14.773	6.326	3.877	0.306	2.805
1998	January	196,735	125,469	63.924	18.145	8.307	4.558	0.360	3.299
	February	33,979	20,466	8.931	2.394	1.285	0.787	0.062	0.570
	March	134,117	84,479	20.270	13.466	5.071	3.108	0.245	2.249
	April	198,676	125,468	43.301	17.563	7.512	4.603	0.363	3.331
	May	152,837	86,703	13.231	13.677	5.779	3.541	0.280	2.563
	June	239,858	151,022	36.561	21.809	9.070	5.558	0.439	4.022
	July	358,207	228,485	115.643	61.424	20.832	8.300	0.655	6.007
	August	705,494	452,723	296.339	135.814	44.491	16.347	1.291	11.830
	September	436,445	276,895	103.509	58.306	24.289	10.113	0.798	7.318
	October	401,532	259,110	115.176	54.736	20.887	9.304	0.735	6.733
	November	351,549	226,865	27.872	30.112	15.386	8.146	0.643	5.895
	December	333,212	215,424	26.485	30.232	14.688	7.721	0.610	5.587
1999	January	301,684	195,310	55.982	23.133	11.407	6.990	0.552	5.059
	February	297,928	192,819	63.922	21.081	11.265	6.903	0.545	4.996
	March	261,560	168,643	65.694	18.605	10.026	6.061	0.478	4.386
	April	226,922	146,349	47.026	20.446	9.531	5.258	0.415	3.805
	May	294,553	188,574	51.696	34.797	16.315	6.825	0.539	4.939
	June	392,018	251,872	81.104	49.235	21.870	9.083	0.717	6.573
	July	439,304	278,287	88.949	71.115	30.671	10.179	0.804	7.366
	August	399,283	253,987	77.634	53.389	23.163	9.252	0.730	6.695
	September	490,556	311,648	132.979	70.735	29.268	11.367	0.897	8.226
	October	679,393	433,636	206.593	138.863	45.395	15.742	1.243	11.392
	November	594,174	385,050	50.778	102.353	32.140	13.767	1.087	9.963
	December	518,079	338,307	46.323	92.022	27.828	12.004	0.948	8.687
2000	January	710,231	460,241	170.499	139.403	44.068	16.457	1.299	11.909
	February	583,610	378,012	156.245	88.688	34.527	13.523	1.068	9.786
	March	346,920	227,312	87.264	32.329	13.118	8.038	0.635	5.817
	April	164,023	107,005	49.541	15.409	6.501	3.801	0.300	2.750
	May	454,570	293,318	151.309	98.139	30.187	10.533	0.832	7.622
	June	804,394	521,606	337.131	169.941	51.062	18.638	1.471	13.488
	July	792,721	513,831	381.986	161.896	49.632	18.368	1.450	13.293
	August	-	-	-	-	-	-	-	-
	September	-	-	-	-	-	-	-	-
	October	-	-	-	-	-	-	-	-
	November	-	-	-	-	-	-	-	-
	December	-	-	-	-	-	-	-	-

36-MONTH AVERAGE EMISSIONS - COMBINED

Year Ending	Month Ending	Natural Gas Consumption (EBs)	Gross Power Generation (MW-hr)	Emissions (tons)					
				CO	NOx	BARCT NOx	PM	SOx	VOC
1999	December	3,687,950	2,360,504	819	490	188	85.5	6.75	61.8
2000	January	3,894,657	2,495,652	867	535	202	90.2	7.12	65.3
	February	4,061,855	2,604,871	914	562	212	94.1	7.43	68.1
	March	4,144,846	2,660,421	938	570	216	96.0	7.58	69.5
	April	4,111,312	2,638,214	929	566	214	95.3	7.52	68.9
	May	4,143,996	2,658,466	943	579	218	96.0	7.58	69.5
	June	4,360,699	2,800,130	1,045	630	233	101	7.98	73.1
	July	4,540,246	2,916,459	1,148	675	246	105	8.31	76.1
	August								
	September								
	October								
	November								
	December								

24-MONTH AVERAGE EMISSIONS - COMBINED

Year Ending	Month Ending	Natural Gas Consumption (EBs)	Gross Power Generation (MW-hr)	Emissions (tons)					
				CO	NOx	BARCT NOx	PM	SOx	VOC
1998	December	3,084,198	1,968,516	744	387	148	71.5	5.64	51.7
1999	January	3,189,986	2,038,771	760	396	152	73.9	5.84	53.5
	February	3,297,941	2,110,003	784	403	156	76.4	6.03	55.3
	March	3,379,747	2,163,994	808	408	159	78.3	6.18	56.7
	April	3,360,895	2,150,357	794	405	159	77.9	6.15	56.4
	May	3,329,914	2,128,362	765	393	157	77.2	6.09	55.8
	June	3,448,779	2,205,991	790	409	165	79.9	6.31	57.8
	July	3,541,392	2,262,712	798	431	175	82.1	6.48	59.4
	August	3,601,190	2,300,134	800	441	181	83.4	6.59	60.4
	September	3,640,790	2,323,948	810	444	184	84.4	6.66	61.0
	October	3,873,121	2,472,507	888	499	202	89.7	7.08	64.9
	November	4,043,662	2,582,486	903	538	212	93.7	7.40	67.8
	December	4,219,048	2,698,795	920	577	223	97.8	7.72	70.7
2000	January	4,475,795	2,866,181	973	637	241	103.7	8.19	75.1
	February	4,750,611	3,044,954	1,047	681	258	110.1	8.69	79.7
	March	4,857,013	3,116,370	1,080	690	262	112.5	8.88	81.4
	April	4,839,686	3,107,139	1,084	689	261	112.1	8.85	81.2
	May	4,990,553	3,210,446	1,153	731	273	115.6	9.13	83.7
	June	5,272,821	3,395,738	1,303	805	294	122.2	9.65	88.4
	July	5,490,078	3,538,411	1,436	855	309	127.2	10.04	92.1
	August								
	September								
	October								
	November								
	December								

DUKE ENERGY POWER SERVICES
MORRO BAY POWER PLANT

36 MONTH BASELINE

Unit	Emissions (tons)				
	CO	NOx	PM	SOx	VOC
1	57.1	141.5	10.43	0.82	7.55
2	18.8	198.1	12.2	0.97	8.86
3	539	148.7	40.2	3.17	29.1
4	533	186.5	42.3	3.34	30.6
Totals	1,148	675	105	8.31	76.1

Unit	Emission Reduction Credits (tons)				
	CO	BARCT - NOx	PM	SOx	VOC
1	45.7	51.1	8.34	0.66	6.04
2	15.0	60.0	9.80	0.77	7.09
3	432	65.6	32.2	2.54	23.3
4	426	69.1	33.9	2.67	24.5
Totals	918	246	84.2	6.64	60.9

24 MONTH BASELINE

Unit	Emissions (tons)				
	CO	NOx	PM	SOx	VOC
1	80.0	193	14.2	1.12	10.27
2	24.8	274	16.8	1.33	12.2
3	645	171	46.9	3.70	33.9
4	686	218	49.3	3.89	35.7
Totals	1,436	855	127	10.04	92.1

Notes:
Baseline periods encompass the 36- and 24-month periods ending July 2000

Table 6.2-1.1
Historical Generation and Fuel Use for Units 1 through 4

	1995	1996	1997	1998	1999	2000 (1)	3-year Baseline
Generation, MWh							
Unit 1	44,848	61,569	86,003	179,133	264,837	345,115	277,914
Unit 2	115,925	80,866	65,840	172,824	412,530	336,932	322,098
Unit 3	183,282	749,212	900,366	889,198	1,216,084	898,597	1,135,047
Unit 4	842,777	569,131	631,714	1,011,954	1,251,030	920,680	1,181,399
Total, all units	1,186,832	1,460,778	1,683,923	2,253,109	3,144,481	2,501,324	2,916,459
Fuel Use, MMBtu							
Unit 1	464,862	645,013	903,137	1,821,025	2,689,750	3,456,676	2,813,258
Unit 2	1,260,457	857,005	693,022	1,785,719	4,233,350	3,425,296	3,303,775
Unit 3	1,809,928	7,387,326	8,706,970	8,598,950	11,582,663	8,473,445	10,843,380
Unit 4	7,684,201	5,571,525	6,107,835	9,935,813	12,090,825	8,747,523	11,416,127
Total, all units	11,219,447	14,460,868	16,410,963	22,141,506	30,596,588	24,102,940	28,376,540

Note: (1) January through July

Table 6.2-1.2
Calculation of Emissions from Existing Boilers

Boiler 1	1700 MMBtu/hr heat input			
Pollutant	Baseline Fuel Use (MMBtu)	Baseline Emissions (tons)	Emission Factor (lb/MMBtu)	Max. Hourly Emissions, lb/hr
NOx	2,813,258	141.5	0.101	171.04
SO2		0.8	0.00059	1.00
CO		57.1	0.0406	69.00
PM10		10.4	0.00741	12.60

Boiler 2	1700 MMBtu/hr heat input			
Pollutant	Baseline Fuel Use (MMBtu)	Baseline Emissions (tons)	Emission Factor (lb/MMBtu)	Max. Hourly Emissions, lb/hr
NOx	3,303,775	198.1	0.120	203.88
SO2		1.0	0.00059	1.00
CO		18.8	0.0114	19.35
PM10		12.2	0.00741	12.60

Boiler 3	3500 MMBtu/hr heat input			
Pollutant	Baseline Fuel Use (MMBtu)	Baseline Emissions (tons)	Emission Factor (lb/MMBtu)	Max. Hourly Emissions, lb/hr
NOx	10,843,380	148.7	0.027	95.97
SO2		3.2	0.00059	2.05
CO		539.5	0.100	348.26
PM10		40.2	0.0074	25.95

Boiler 4	3500 MMBtu/hr heat input			
Pollutant	Baseline Fuel Use (MMBtu)	Baseline Emissions (tons)	Emission Factor (lb/MMBtu)	Max. Hourly Emissions, lb/hr
NOx	11,416,127	186.5	0.033	114.39
SO2		3.3	0.00059	2.05
CO		532.6	0.093	326.55
PM10		42.3	0.0074	25.95

Table 6.2-1.3
Emissions from New Turbines

	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
	85 deg Full Load no DB	85 deg Full Load w/ DB	85 deg 50% Load	34 deg Full Load no DB	34 deg Full Load w/ DB	34 deg 50% Load
Ambient Temp, F	85	85	85	34	34	34
GT Load	100	100	50	100	100	50
GT heat input, MMBtu/hr (HHV)	1651.7	1651.7	1077.8	1850.4	1850.4	1091.0
DB heat input, MMBtu/hr (HHV)	0.0	426.2	0.0	0.0	290.8	0.0
Stack flow, lb/hr	3,308,753	3,327,995	2,282,231	3,711,235	3,724,364	2,241,447
Stack flow, acfm	927,709	922,182	607,581	1,040,619	1,033,958	598,918
Stack temp, F	187	177	160	193	185	162
Stack exhaust, vol %						
O2 (dry)	13.66	11.69	14.18	13.79	12.62	13.96
CO2 (dry)	4.16	5.27	3.86	4.08	4.75	3.99
H2O	10.18	11.91	7.65	7.81	8.90	7.85
Emissions						
NOx, ppmvd @ 15% O2	2.5	2.5	2.5	2.5	2.5	2.5
NOx, lb/hr	14.9	18.75	9.75	16.72	19.32	9.86
NOx, lb/MMBtu	0.0090	0.0090	0.0090	0.0090	0.0090	0.0090
SO2, ppmvd @ 15% O2	0.139	0.139	0.139	0.139	0.139	0.139
SO2, lb/hr	1.157	1.45	0.75	1.30	1.50	0.77
SO2, lb/MMBtu	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007
CO, ppmvd @ 15% O2	6.00	6.00	6.00	6.00	6.00	6.00
CO, lb/hr	21.79	27.41	14.23	24.41	28.26	14.40
CO, lb/MMBtu	0.0132	0.0132	0.0132	0.0132	0.0132	0.0132
VOC, ppmvd @ 15% O2	1.14	2.00	1.36	1.16	2.00	1.40
VOC, lb/hr	2.38	5.23	1.85	2.71	5.39	1.93
VOC, lb/MMBtu	0.0014	0.0025	0.0017	0.0015	0.0025	0.0018
PM10, lb/hr	11.0	13.26	11.0	11.0	11.9	11.00
PM10, lb/MMBtu	0.0067	0.0064	0.0102	0.0059	0.0056	0.0101
PM10, gr/dscf	0.0016	0.0023	0.0022	0.0014	0.0018	0.0023

Table 6.2-1.4a
Summary of Startup Emissions Data - pounds per hour

Project		Notes	POC	CO	NOx	SOx	PM10
Crockett Cogeneration		Source Tests					
	6/96 avg	(Note 1)	54	46	59	-	-
	6/97 avg		<1	31	41	-	-
	min run		<1	27	9	-	-
	max run		59	49	95	-	-
Crockett Cogeneration		FDOC (Note 2)	170	385	160	-	-
SF Energy		FDOC	299	437	77	-	-
Sutter		From					
	Cold Start	Westinghouse	-	838	175	-	-
	Hot Start		-	902	170	-	-
Sutter		FDOC					
	Cold Start	(Note 3)	1.1	838	175	2.7	9.0
	Hot Start		1.1	902	170	2.7	9.0
Westinghouse		Note 4					
	Cold Start		292	1722	183	3	28
	Warm Start		296	1625	221	3	25
	Hot Start		442	2142	217	4	33
Bechtel - DEC		From					
	Cold Start	Westinghouse	437	3317	168	-	7
	Hot Start	Note 5	520	7343	189	-	8
Used in AFC		Note 6					
	Cold Start		16	620	80	1.3	9

Notes:

1. Minimum and maximum values are based on the six individual runs that comprise the two sets of tests.
2. Permit conditions have not been carried forward into the permit to operate, and are no longer in effect.
3. Values shown are from the engineering analysis; there are no proposed permit conditions for startup emissions limits in the proposed FDOC.
4. Westinghouse provided data for the total plant (3 turbines) on a lbs/start basis. The above lbs/hr values were calculated assuming a 3 hour starting period per turbine for a cold start; 2 hours for a warm start; and 1 hour for a hot start. Data do not reflect the performance of oxidation catalysts or CO catalysts.
5. Bechtel estimates are 140 minutes for cold start for first engine; 40 minutes for cold start for second and third engines; and 30 minutes for hot start for each engine.
6. POC values are three times full load emission rates. CO values are expected average values. NOx values are 30% higher than the higher of the two Crockett test averages, rounded up to the nearest 5 lbs/hr. SOx and PM10 values are the full load emission rates.

Table 6.2-1.4b
Summary of Startup Emissions Data - pounds per start per turbine

Project	Notes	POC	CO	NOx	SOx	PM10
Crockett Cogeneration	Source Tests					
6/96 avg	(Note 1)	71	62	79	-	-
6/97 avg		1	41	54	-	-
min run		<1	36	12	-	-
max run		79	66	127	-	-
Crockett Cogeneration	FDOC (Note 2)	340	770	320	-	-
SF Energy	FDOC (Note 3)	299	437	77	-	-
Sutter	From					
Cold Start	Westinghouse	-	611	2932	-	-
Hot Start		-	339	1804	-	-
Sutter	Proposed FDOC					
Cold Start	(Note 4)	3	2514	525	8	27
Hot Start		1	902	170	3	9
Westinghouse	Note 5					
Cold Start		875	5167	550	8	83
Warm Start		592	3250	442	5	50
Hot Start		442	2142	217	4	33
Bechtel - DEC	From					
Cold Start	Westinghouse	1019	7740	391	-	17
Hot Start		520	3671	189	-	4
Used in AFC	Note 6					
Cold Start		64	2480	320	5.2	36

Notes:
1. Data extrapolated from reported hourly values by ratio of 80/60.
2. Values based on maximum two hours per startup.
3. Values based on maximum one hour per startup.
4. Values based on maximum three hours per cold start, one hour per hot start.
5. Westinghouse provided data for the total plant (3 turbines). Data do not reflect the performance of oxidation catalysts or CO catalysts.
6. Based on maximum four hours per startup.

Table 6.2-1.5
Calculation of Daily and Annual Fuel Use

	Operating Hours			Fuel Use
	max. hour	hrs/day	hrs/yr	(MMBtu/hr)
Turbine 1, no DB	0	8	4400	1850.4
Turbine 2, no DB	0	8	4400	1850.4
Turbine 3 no DB	0	8	4400	1850.4
Turbine 4, no DB	0	8	4400	1850.4
Turbine 1, w/ DB	1	16	4000	2141.2
Turbine 2, w/ DB	1	16	4000	2141.2
Turbine 3, w/ DB	1	16	4000	2141.2
Turbine 4, w/ DB	1	16	4000	2141.2

	Fuel Use		
	MMBtu/hr	MMBtu/day	MMBtu/yr
Turbine 1, no DB	n/a	14,803.2	8,141,760
Turbine 2, no DB	n/a	14,803.2	8,141,760
Turbine 3 no DB	n/a	14,803.2	8,141,760
Turbine 4, no DB	n/a	14,803.2	8,141,760
Turbine 1, w/ DB	2,141.2	34,259.2	8,564,800
Turbine 2, w/ DB	2,141.2	34,259.2	8,564,800
Turbine 3, w/ DB	2,141.2	34,259.2	8,564,800
Turbine 2, w/ DB	2,141.2	34,259.2	8,564,800
Total, All Units	**8,564.8**	**196,250**	**66,826,240**

Maximum daily fuel use is calculated assuming that each turbine operates for 8 hours without duct firing and for 16 hours with duct firing. Therefore, for each turbine the maximum daily heat input is:

(1850.4 MMBtu/hr * 8 hrs/day) + (2141.2 MMBtu/hr * 16 hrs/day)

= 14,803.2 + 34,259.2 = 49,062.4 MMBtu/day per turbine

Maximum annual fuel use is calculated assuming that each turbine operates for 4400 hours per year without duct firing and for 4000 hours per year with duct firing. Therefore, for each turbine the maximum annual heat input is:

(1850.4 MMBtu/hr * 4400 hrs/yr) + (2141.2 MMBtu/hr * 4000 hrs/yr)

= 8.141,760 + 8,564,800 = 16,706,560 MMBtu/yr per turbine

Table 6.2-1.6
Detailed Calculations for Maximum Hourly, Daily and Annual Criteria Pollutant Emissions

Maximum Hourly, Daily and Annual Emissions		Base Load		Start Emissions		Quarterly Avg Levels (ppmc) (see notes)		NOx			SO2	CO			POC			PM10
								Base Load	Ann Avg	Start		Base Load	Ann Avg	Start	Base Load	Ann Avg	Start	
	max. hour	hrs/day	hrs/yr	hrs/day	hrs/yr	NOx	CO	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
Turbine 1, no DB	1	4	4000	4	400	1.98	6.00	16.72	13.24	80	1.30	24.41	24.41	620.0	2.71	2.71	16.0	11.00
Turbine 2, no DB	1	4	4000	4	400	1.98	6.00	16.72	13.24	80	1.30	24.41	24.41	620.0	2.71	2.71	16.0	11.00
Turbine 3, no DB	0	4	4000	4	400	1.98	6.00	16.72	13.24	80	1.30	24.41	24.41	620.0	2.71	2.71	16.0	11.00
Turbine 4, no DB	0	4	4000	4	400	1.98	6.00	16.72	13.24	80	1.30	24.41	24.41	620.0	2.71	2.71	16.0	11.00
Turbine 1, w/ DB	0	16	4000	0	0	1.98	6.00	19.32	15.30	80	1.45	28.26	28.26	620.0	5.39	5.39	16.0	13.30
Turbine 2, w/ DB	0	16	4000	0	0	1.98	6.00	19.32	15.30	80	1.45	28.26	28.26	620.0	5.39	5.39	16.0	13.30
Turbine 3, w/ DB	1	16	4000	0	0	1.98	6.00	19.32	15.30	80	1.45	28.26	28.26	620.0	5.39	5.39	16.0	13.30
Turbine 4, w/ DB	1	16	4000	0	0	1.98	6.00	19.32	15.30	80	1.45	28.26	28.26	620.0	5.39	5.39	16.0	13.30

	NOx			SO2			CO			POC			PM10		
	Max	Max	Total	Max	Max	Total	Max	Max	Total	Max	Max	Total	Max	Max	Total
	lb/hr	lb/day	tpy	lb/hr	lb/day	tpy	lb/hr	lb/day	tpy	lb/hr	lb/day	tpy	lb/hr	lb/day	tpy
Turbine 1, no DB	80.0	386.9	42.5	0.0	10.4	2.9	620.0	2,577.6	172.8	16.0	74.8	8.6	0.0	88.0	24.2
Turbine 2, no DB	80.0	386.9	42.5	0.0	10.4	2.9	620.0	2,577.6	172.8	16.0	74.8	8.6	0.0	88.0	24.2
Turbine 3, no DB	0.0	386.9	42.5	0.0	10.4	2.9	0.0	2,577.6	172.8	0.0	74.8	8.6	0.0	88.0	24.2
Turbine 4, no DB	0.0	386.9	42.5	0.0	10.4	2.9	0.0	2,577.6	172.8	0.0	74.8	8.6	0.0	88.0	24.2
Turbine 1, w/ DB	0.0	309.1	30.6	1.5	23.2	2.9	0.0	452.2	56.5	0.0	86.2	10.8	13.3	212.8	26.6
Turbine 2, w/ DB	0.0	309.1	30.6	1.5	23.2	2.9	0.0	452.2	56.5	0.0	86.2	10.8	13.3	212.8	26.6
Turbine 3, w/ DB	19.3	309.1	30.6	1.5	23.2	2.9	28.3	452.2	56.5	5.4	86.2	10.8	13.3	212.8	26.6
Turbine 4, w/ DB	19.3	309.1	30.6	1.5	23.2	2.9	28.3	452.2	56.5	5.4	86.2	10.8	13.3	212.8	26.6
Total	198.6	2784.0	292.3	5.8	134.4	23.0	1296.5	12,119.2	917.4	42.8	644.3	77.6	53.2	1203.2	203.2
	lb/hr	lb/day	tpy	lb/hr	lb/day	tpy	lb/hr	lb/day	tpy	lb/hr	lb/day	tpy	lb/hr	lb/day	tpy

NOTES TO TABLE 6.2-1.6
DETAILED CALCULATIONS
FOR MAXIMUM HOURLY, DAILY AND ANNUAL
CRITERIA POLLUTANT EMISSIONS

Maximum Hourly Emissions

Maximum hourly NOx, CO and POC and emissions occur when two turbines are starting up and two turbines are at full load with duct firing. Maximum hourly NOx emissions can be calculated as:

(2 turbines * 80 lb/hr) + (2 turbines * 19.32 lb/hr) = 198.1 lb/hr

Maximum hourly SO_2 and PM_{10} emissions occur when all four turbines are at full load with duct firing. For example, maximum hourly SO_2 emissions are:

4 turbines * 1.45 lb/hr = 5.8 lb/hr

Maximum Daily Emissions

Maximum daily NOx, CO and POC emissions occur when each turbine is in startup for four hours, at base load without duct firing for four hours, and at base load with duct firing for 16 hours. For example, maximum daily CO emissions from each turbine are:

(4 hrs/day * 620 lb/hr) + (4 hrs/day * 24.41 lb/hr) + (16 hrs/day * 28.26 lb/hr) = 3,029.8 lb/day

Maximum daily SO_2 and PM_{10} emissions occur when each turbine operates for eight hours at base load without duct firing and for 16 hours at base load with duct firing. Maximum daily PM_{10} emissions from each turbine can be calculated as:

(8 hrs/day * 11 lb/hr) + (16 hrs/day * 13.3 lb/hr) = 300.8 lb/day

Maximum Annual Emissions

Maximum annual NOx emissions will be limited to 292.3 tons per year, or 73.08 tons per quarter, for all four turbines. This is equivalent to an quarterly average NOx emission concentration of 1.98 ppm @ 15% O_2 (except during startup). The quarterly NOx cap was calculated as:

(400 hrs/quarter * 80 lb/hr) + (4000 hrs/quarter * 13.24 lb/hr) * (4000 hrs/quarter * 15.30 lb/hr)
= 73.08 tons for four turbines

Maximum annual CO and POC emissions are calculated assuming that each turbine has 400 hours of startup, 4000 hours of base load operation without duct firing, and 4000 hours of base load operation with duct firing each year. Maximum annual POC emissions for a single turbine can be calculated as:

(400 hrs/yr * 620 lb/hr) + (4000 hrs/yr * 24.41 lb/hr) + (4000 lb/hr * 28.26 lb/hr) = 229.34 tpy

Maximum annual SO_2 and PM_{10} emissions occur when each turbine operates for 4400 hours per year at base load without duct firing and 4000 hours per year at base load with duct firing. Annual SO_2 emissions for a single turbine can be calculated as:

(4400 hrs/yr * 1.30 lb/hr) + (4000 hrs/yr * 1.45 lb/hr) = 5.76 tpy

Table 6.2-1.7
Calculation of Noncriteria Pollutant Emissions from Existing Boilers

Boiler 1

Compound	Nat. Gas Emission Factor, lb/MMscf (1)	Max Hourly Emissions on Gas, lb/hr (2)	Annual Emissions, ton/yr (3)	One-hour Em Rates, g/s	Annual Em Rates, g/s
Benzene	1.21E-03	4.03E-03	2.05E-03	5.07E-04	5.89E-05
Formaldehyde	1.27E-02	4.23E-02	2.15E-02	5.32E-03	6.18E-04

Notes: (1) From 1991 AB2588 report.
(2) Based on maximum hourly boiler natural gas fuel use of 3.33 MMscf/hr
(3) Based on baseline boiler natural gas fuel use of 3,382 MMscf/yr

Boiler 2

Compound	Nat. Gas Emission Factor, lb/MMscf (1)	Max Hourly Emissions on Gas, lb/hr (2)	Annual Emissions, ton/yr (3)	One-hour Em Rates, g/s	Annual Em Rates, g/s
Benzene	1.21E-03	4.03E-03	2.05E-03	5.07E-04	5.89E-05
Formaldehyde	1.27E-02	4.23E-02	2.15E-02	5.32E-03	6.18E-04

Notes: (1) From 1991 AB2588 report.
(2) Based on maximum hourly boiler natural gas fuel use of 3.33 MMscf/hr
(3) Based on baseline boiler natural gas fuel use of 3,352 MMscf/yr

Boiler 3

Compound	Nat. Gas Emission Factor, lb/MMscf (1)	Max Hourly Emissions on Gas, lb/hr (2)	Annual Emissions, ton/yr (3)	One-hour Em Rates, g/s	Annual Em Rates, g/s
Benzene	1.21E-03	4.14E-03	6.42E-03	5.22E-04	1.85E-04
Formaldehyde	1.27E-02	4.35E-02	6.74E-02	5.48E-03	1.94E-03

Notes: (1) From 1991 AB2588 report.
(2) Based on maximum hourly boiler natural gas fuel use of 3.42 MMscf/hr
(3) Based on baseline boiler natural gas fuel use of 10,610 MMscf/yr

Boiler 4

Compound	Nat. Gas Emission Factor, lb/MMscf (1)	Max Hourly Emissions on Gas, lb/hr (2)	Annual Emissions, ton/yr (3)	One-hour Em Rates, g/s	Annual Em Rates, g/s
Benzene	1.21E-03	4.14E-03	6.76E-03	5.22E-04	1.94E-04
Formaldehyde	1.27E-02	4.35E-02	7.09E-02	5.48E-03	2.04E-03

Notes: (1) From 1991 AB2588 report.
(2) Based on maximum hourly boiler natural gas fuel use of 3.42 MMscf/hr
(3) Based on baseline boiler natural gas fuel use of 11,170 MMscf/yr

Table 6.2-1.8
Calculation of Noncriteria Pollutant Emissions from Gas Turbines

Compound	Emission Factor, lb/MMscf (1)	(each turbine) Max Hourly Emissions, lb/hr (2)	Annual Emissions, ton/yr (3)	Emission Rates for Modeling (each turbine) One-hour Em Rates, g/s	Annual Em Rates, g/s	Total, 4 turbines (tpy)
Ammonia	(5)	14.31	60.10	1.80E+00	1.73E+00	240.41
Hazardous Air Pollutants						
Acetaldehyde	6.86E-02	0.14	0.56	1.81E-02	1.61E-02	2.24
Acrolein (4)	6.43E-03	1.35E-02	0.05	1.70E-03	1.51E-03	0.21
Benzene	1.36E-02	2.85E-02	0.11	3.59E-03	3.20E-03	0.44
1,3-Butadiene	1.27E-04	2.66E-04	1.04E-03	3.35E-05	2.99E-05	4.15E-03
Ethylbenzene	1.79E-02	3.75E-02	0.15	4.73E-03	4.21E-03	0.59
Formaldehyde	1.10E-01	0.23	0.90	2.90E-02	2.59E-02	3.60
Naphthalene	1.66E-03	3.48E-03	1.36E-02	4.38E-04	3.90E-04	5.43E-02
PAHs (6)	6.60E-04	1.38E-03	5.39E-03	1.74E-04	1.55E-04	2.16E-02
Propylene oxide	4.78E-02	1.00E-01	0.39	1.26E-02	1.12E-02	1.56
Toluene	7.10E-02	0.15	0.58	1.87E-02	1.67E-02	2.32
Xylene	2.61E-02	5.47E-02	0.21	6.89E-03	6.14E-03	0.85
Total HAPs			2.97			11.90

Notes: (1) From Ventura County APCD and CATEF databases.
(2) Based on maximum hourly turbine fuel use of 2141.2 MMBtu/hr and fuel HHV of 1022 Btu/scf. 2.10 MMscf/hr
(3) Based on maximum annual turbine fuel use of 16,706,560 MMBtu/yr and fuel HHV of 1022 Btu/scf. 16,347 MMscf/yr
(4) Based on test result from Frame turbine only.
(5) Based on 5 ppm ammonia slip from SCR system.
(6) Polycyclic aromatic hydrocarbons.

Table 6.2-1.9
Calculation of Noncriteria Pollutant Emissions from Other Power Plant Activities

Diesel Fire Pump Engines

		Engine #2				Engine #3				Engine #4			
Compound	Diesel Emission Factor, lb/M gal (1)	Max Hourly Emissions, lb/hr (2)	Annual Emissions, ton/yr (3)	One-hour Em Rates, g/s	Annual Em Rates, g/s	Max Hourly Emissions, lb/hr (3)	Annual Emissions, ton/yr (3)	One-hour Em Rates, g/s	Annual Em Rates, g/s	Max Hourly Emissions, lb/hr (4)	Annual Emissions, ton/yr (4)	One-hour Em Rates, g/s	Annual Em Rates, g/s
Arsenic (Units 2 and 3)	0.00954	9.54E-05	2.73E-07	1.20E-05	7.86E-09	1.19E-04	3.61E-07	1.50E-05	1.04E-08				
Arsenic (Unit 4)	0.00881									1.11E-04	4.01E-07	1.40E-05	1.15E-08
Benzene	0.7425	7.43E-03	2.13E-05	9.36E-04	6.12E-07	9.28E-03	2.81E-05	1.17E-03	8.08E-07	9.36E-03	3.38E-05	1.18E-03	9.72E-07
Beryllium	0.00367	3.67E-05	1.05E-07	4.62E-06	3.02E-09	4.59E-05	1.39E-07	5.78E-06	3.99E-09	4.62E-05	1.67E-07	5.83E-06	4.80E-09
Cadmium	0.022	2.20E-04	6.30E-07	2.77E-05	1.81E-08	2.75E-04	8.32E-07	3.47E-05	2.39E-08	2.77E-04	1.00E-06	3.49E-05	2.88E-08
Chromium VI	0.00003	3.00E-07	8.60E-10	3.78E-08	2.47E-11	3.75E-07	1.13E-09	4.73E-08	3.26E-11	3.78E-07	1.36E-09	4.76E-08	3.93E-11
Copper	0.022	2.20E-04	6.30E-07	2.77E-05	1.81E-08	2.75E-04	8.32E-07	3.47E-05	2.39E-08	2.77E-04	1.00E-06	3.49E-05	2.88E-08
Formaldehyde	0.05589	5.59E-04	1.60E-06	7.04E-05	4.61E-08	6.99E-04	2.11E-06	8.80E-05	6.08E-08	7.04E-04	2.54E-06	8.87E-05	7.31E-08
Lead	0.00734	7.34E-05	2.10E-07	9.25E-06	6.05E-09	9.18E-05	2.78E-07	1.16E-05	7.98E-09	9.25E-05	3.34E-07	1.17E-05	9.60E-09
Manganese	0.00734	7.34E-05	2.10E-07	9.25E-06	6.05E-09	9.18E-05	2.78E-07	1.16E-05	7.98E-09	9.25E-05	3.34E-07	1.17E-05	9.60E-09
Mercury	0.00022	2.20E-06	6.30E-09	2.77E-07	1.81E-10	2.75E-06	8.32E-09	3.47E-07	2.39E-10	2.77E-06	1.00E-08	3.49E-07	2.88E-10
Nickel	0.022	2.20E-04	6.30E-07	2.77E-05	1.81E-08	2.75E-04	8.32E-07	3.47E-05	2.39E-08	2.77E-04	1.00E-06	3.49E-05	2.88E-08
PAH	0.00306	3.06E-05	8.77E-08	3.86E-06	2.52E-09	3.83E-05	1.16E-07	4.82E-06	3.33E-09	3.86E-05	1.39E-07	4.86E-06	4.00E-09
Phosphorus	0.22	2.20E-03	6.30E-06	2.77E-04	1.81E-07	2.75E-03	8.32E-06	3.47E-04	2.39E-07	2.77E-03	1.00E-05	3.49E-04	2.88E-07
Selenium (Units 2 and 3)	0.000734	7.34E-06	2.10E-08	9.25E-07	6.05E-10	9.18E-06	2.78E-08	1.16E-06	7.98E-10				
Selenium (Unit 4)	0.00147									1.85E-05	6.69E-08	2.33E-06	1.92E-09
Zinc	0.022	2.20E-04	6.30E-07	2.77E-05	1.81E-08	2.75E-04	8.32E-07	3.47E-05	2.39E-08	2.77E-04	1.00E-06	3.49E-05	2.88E-08
Diesel particulate (6)	0.31	--	1.23E-03	--	3.55E-05	--	1.63E-03	--	4.68714E-05	--	1.96E-03	--	5.63833E-05

Notes:

1. From 1991 AB2588 report.
2. Based on fuel use of 10.0 gal/hr and 57.3 gal/yr
3. Based on fuel use of 12.5 gal/hr and 75.6 gal/yr
4. Based on fuel use of 12.6 gal/hr and 91.0 gal/yr
5. From AP-42, Table 3.3-1, units are lb/MMBtu. Assume 139,000 Btu/gal

Table 6.2-1.9 (cont'd)

Emergency Diesel Generator

Compound	Diesel Emission Factor, lb/M gal (1)	Max Hourly Emissions, lb/hr (2)	Annual Emissions, ton/yr (3)	One-hour Em Rates, g/s	Annual Em Rates, g/s
Arsenic	0.0081	8.505E-05	2.69E-07	1.07E-05	7.74E-09
Benzene	0.7425	7.796E-03	2.47E-05	9.82E-04	7.10E-07
Beryllium	0.00367	3.854E-05	1.22E-07	4.86E-06	3.51E-09
Cadmium	0.022	2.31E-04	7.31E-07	2.91E-05	2.10E-08
Chromium VI	0.00003	3.15E-07	9.97E-10	3.97E-08	2.87E-11
Copper	0.022	2.31E-04	7.31E-07	2.91E-05	2.10E-08
Formaldehyde	0.05589	5.87E-04	1.86E-06	7.39E-05	5.34E-08
Lead	0.00734	7.71E-05	2.44E-07	9.71E-06	7.02E-09
Manganese	0.00734	7.71E-05	2.44E-07	9.71E-06	7.02E-09
Mercury	0.00022	2.31E-06	7.31E-09	2.91E-07	2.10E-10
Nickel	0.022	2.31E-04	7.31E-07	2.91E-05	2.10E-08
PAH	0.00306	3.21E-05	1.02E-07	4.05E-06	2.93E-09
Phosphorus	0.22	2.31E-03	7.31E-06	2.91E-04	2.10E-07
Selenium	0.0044	4.62E-05	1.46E-07	5.82E-06	4.21E-09
Zinc	0.022	2.31E-04	7.31E-07	2.91E-05	2.10E-08
Diesel particulate (3)	0.31	--	1.43E-03	--	4.12E-05

Notes:
1. From 1991 AB2588 report.
2. Based on fuel use of 10.5 gal/hr and 66.5 gal/yr
3. From AP-42, Table 3.3-1, units are lb/MMBtu. Assume 139,000 Btu/gal

Gasoline Storage and Dispensing

Activity	Emission Factor, lb/M gal (1)	Max Hourly Emissions, lb/hr (2)	Annual Emissions, ton/yr (3)	One-hour Em Rates, g/s	Annual Em Rates, g/s
Storage (includes filling tank)	8.3	--	5.14E-03	--	--
Dispensing (includes spillage)	11.7	5.85E-01	7.24E-03	--	--
Total		5.85E-01	1.24E-02	7.37E-02	3.56E-04

Note:
1. From AP-42, Table 5.2-7
2. Based on maximum hourly dispensing rate of 50 gal/hr and annual throughput of 1238.3 gal/yr

Boiler Chemical Charging

Pollutant	Max Hourly Emissions, lb/hr (1)	Annual Emissions, ton/yr (1)	One-hour Em Rates, g/s	Annual Em Rates, g/s
Ammonia	1.23E-01	0.2763	1.55E-02	7.95E-03

Notes:
1. Based on 30 ppb hydrazine in blowdown and usage factors in 1991 AB2588 report.

Table 6.2-1.10

Ammonia Emissions Calculations

Calculation of ammonia emissions from the gas turbines is based on the proposed ammonia slip limit of 5 ppmvd.

Gas Turbines

Maximum hourly ammonia emissions from the gas turbines occur when the turbines are operating at 100% load with duct firing and the ambient temperature is 34 deg F. Under these conditions, the exhaust flow rate has been calculated to be 759,401 dscfm at 12.62% O_2. The 5 ppm ammonia slip rate at 15% O_2 is calculated as:

5 ppm @ 15% O_2 * 4.4852×10^{-8} lb/scf per ppm * 759,401 scf/min * (20.9-12.62)/(20.9-15) x 60 min/hr

= 14.3 lb/hr (each turbine)

APPENDIX 6.2-2

MODELING ANALYSIS

ATTACHMENT 6.2-2.1

MODELING PROTOCOL AND RELATED CORRESPONDENCE

sierra research

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June 2, 2000

Mr. Robert W. Carr, APCO
San Luis Obispo County Air Pollution Control District
3433 Roberto Court
San Luis Obispo, CA 93401-7126

Dear Mr. Carr:

As you know, Duke Energy Power Services will be filing a revised application with the San Luis Obispo County APCD for an Authority to Construct and a Determination of Compliance for a new combined cycle gas turbine project at Duke's Morro Bay power plant in Morro Bay. The project will be a major modification to an existing major source and will be subject to District requirements for air quality modeling analyses. In addition, as the project will be subject to PSD review a PSD permit will also have to be obtained from EPA. Attached for your review and approval is a description of the analytical approach that will be used to comply with District and EPA modeling requirements for the project. This revised protocol addresses comments received from the District in January and March of this year.

We look forward to meeting with you on Tuesday, June 6, to discuss this protocol and other issues related to the air permit for the project. If you have any questions, please do not hesitate to call.

Sincerely,

Gary Rubenstein

attachment

cc: Gary Willey, SLOCAPCD
David Albright, EPA Region IX
Mark Seedall, Duke Energy
Wayne Hoffman, Duke Energy
Mark Hays, Duke Energy
Bob Mason, TRC
Keith Golden, CEC

Revised Protocol for Evaluating Ambient Air Quality Impacts of the Proposed Expansion Project at Morro Bay, CA

Introduction

Duke Energy Power Services, LLC (Duke), is planning to construct and operate four new combined-cycle gas turbines at the existing Morro Bay power plant in Morro Bay, California. Duke took over operation of the power plant from Pacific Gas & Electric Company on July 1, 1998. The proposed project will consist of four gas turbines with fired heat recovery steam generators and two steam turbines for a nominal output of 1200 megawatts. The turbines will be General Electric 7251FA units and will be fueled with pipeline quality natural gas. As the project will utilize the existing once-through seawater cooling system, there will be no cooling tower.

As the applicant already owns and operates four boilers at the stationary source, the proposed project will be a major modification to a major facility.

The applicant will submit air quality impact analyses to the San Luis Obispo County Air Pollution Control District (District); the Environmental Protection Agency, Region IX (EPA); and the California Energy Commission (CEC). The modeling analysis will include pollutants for which emissions exceed the PSD significant emissions thresholds of 40 CFR 52.21(m) (shown in Table 1) and the CEC requirements for evaluation of project air quality impacts. The purpose of this document is to establish the protocol for meeting the air quality modeling requirements for the proposed project.

Table 1
PSD Significant Emissions Thresholds

Pollutant	Cumulative Increase (tons/yr)
NOx	40
SO_2	40
CO	100
PM_{10}	15

The project is expected to result in emissions that will exceed PSD significant emissions thresholds for fine particulate (PM_{10}) and, potentially, for oxides of nitrogen (NOx). The project is also expected to require CEC modeling analyses for cumulative impacts and construction impacts.

Emissions from the proposed project are expected to exceed the thresholds defining a major modification for purposes of New Source Review and Prevention of Significant Deterioration (PSD), so will be subject to review under both sets of requirements. Modeled ambient impacts are expected to be well below the levels at which preconstruction monitoring or increments analyses are required. These analyses will be presented in detail in the AFC, the application for a Determination of Compliance, and the application for a PSD Approval to Construct.

Project Location

The proposed project will be located on an eight-acre site in the northwesterly portion of the existing Morro Bay Power Plant property. In general, the Morro Bay Power Plant property is surrounded by light industrial, commercial, marine, residential, and recreational land uses. The power plant property is bordered by the Pacific Ocean, Estero Bay, and Morro Rock to the west and by U.S. Highway 1 to the northeast. A mobile home park and the Lila Kaiser Park are located on the north side of the property. Additional residences and other sensitive receptors are located to the south of the property. A map showing the location of the Morro Bay Power Plant relative to these other properties is included as Figure 1. The air quality impact analyses will include a map showing the plant location, fence lines, and modeling receptors, as well as a plot plan of the plant site indicating final site elevation and heights of facility structures.

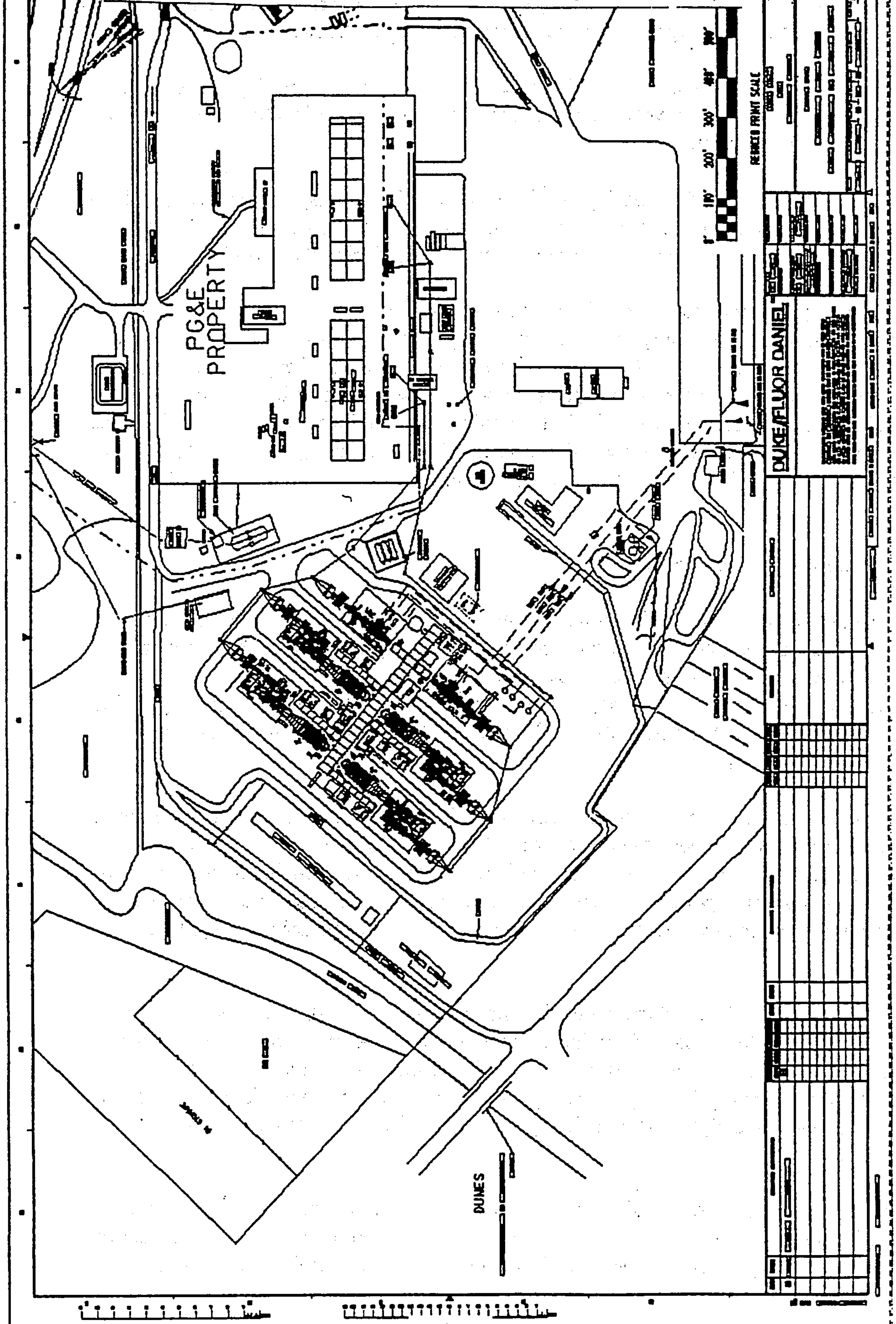
As indicated above, the Pacific Ocean lies less than half a mile to the west. Due east of the site, the hills of the Coast Range rise to heights of 500 to 600 feet within one mile. Approximately 0.6 miles WSW of the power plant lies Morro Rock, which has an elevation of 578 feet.

Meteorological Data

Meteorological data collected by PG&E at the Morro Bay power plant during the three-year period 1994 through 1996 will be used for modeling. Wind speed and direction, sigma theta and temperature data were collected at an elevation of 10 meters. The meteorological data set meets the EPA completeness criterion of 90% on a monthly basis. Upper air data from Vandenburg Air Force Base, 45 miles southeast of the plant site, will be used. As recommended by EPA guidelines for use with onsite meteorological data, the meteorological data preprocessor Meteorological Processor for Regulatory Models (MPRM) will be used to preprocess the meteorological data prior to using the data with the ambient air quality models. Holzworth mixing heights will be substituted for any missing data in the Vandenburg mixing height data set.

Figure 1

Location of the Proposed New Units at Morro Bay Power Plant



A preliminary review of the meteorological data indicates that there may be some periods of missing data. We propose to handle the missing data as follows:

1. If the period of missing data is four hours or less, the missing data will be filled in by linearly interpolating between the data points before and after the missing data period.

2. If the period of missing data is longer than four hours, no substitution will be made and the missing data processing option will be used in the ISCST3 model to invoke the calms processing option during the period.

The District has requested a specific analysis of fog effects on dispersion. Fog is the result of specific meteorological conditions that generally occur in the lower atmosphere. The conditions that produce fog are contained within the mixing height and temperature data collected at or near the power plant that will be used in the ambient air quality analysis. Therefore, the meteorological conditions that produce fog are already included in the meteorological data set that will be used and the requested analysis of dispersion during foggy conditions will automatically be included.

Ambient Air Quality Models

The ambient air quality modeling will be performed in several steps. The first step will be to determine which combination of potential operating loads and ambient conditions will produce the highest modeled impacts from the new turbines. This worst-case operating scenario for the turbines will be determined using the ISCST3 model (Version 99155) to model ambient impacts of NOx, CO, and PM_{10} under all of the potential operating scenarios.

Ambient conditions for evaluating turbine operations will range from design minimum to maximum expected ambient temperatures. The Bowman Engineering BPIP model will be used to determine direction-specific building dimensions so that building downwash effects will be appropriately evaluated. A single combination of turbine parameters, operating load, and ambient temperature will be selected for further modeling based on this analysis.

The second step of the ambient air quality modeling analysis will be the evaluation of maximum modeled impacts from the proposed project. Maximum emission rates will be identified for each averaging period for modeling (including turbine startups and shutdowns, as appropriate). Direction-specific building dimensions will also be included in this modeling analysis so that building downwash effects will be appropriately evaluated.

Potential shoreline and inversion breakup fumigation impacts will be evaluated using the SCREEN3 model. Multiple modeling runs using a shoreline fumigation thermal internal boundary layer (TIBL) factor varying from 2 to 6 will be used to determine the most conservative TIBL factor to use in the shoreline fumigation modeling analysis. As shoreline fumigation conditions are expected to last for a very short time, only one hour of shoreline fumigation impacts will be evaluated.

The SCREEN3 model will also be used to evaluate fumigation impacts for all short-term averaging periods (24 hours or less). The methodology in EPA 454/R-92-019 (Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised) will be followed for this analysis. Combined impacts for all sources under fumigation conditions will be evaluated.

Finally, the ISCST3 model will also be used to model impacts from the existing boilers. This modeling will represent operation of the boilers during the baseline period.

Receptor Grids

Receptors for both the initial (screening) and final modeling analyses will be placed at 25 meters along the facility fenceline. A coarse receptor grid spaced at 180 meters will be used to a distance of 5 kilometers from the facility. Receptors will also be placed in the cities of Cayucos, Los Osos, and Cambria to provide information to residents regarding anticipated impacts. A fine grid of receptors spaced at 60 meters will be used in areas where the coarse grid analysis indicates modeled maxima will be located. If predicted ambient concentrations (modeled impacts plus background concentrations) exceed 75% of the applicable ambient air quality standard, a 30-meter grid will be used to locate and characterize the maximum modeled impacts. In accordance with EPA guidance, overwater receptors will be included in the modeling analysis.

Model Options

The ISCST3 model allows the selection of a number of options that affect model output. The regulatory default options will be used, as listed below.

- Final plume rise
- Buoyancy-induced dispersion
- Stack tip downwash
- Rural dispersion coefficients
- Calms processing
- Default wind profile exponents based ural dispersion
- Default vertical temperature gradients
- Upper-bound concentration estimates for sources influenced by building downwash from super-squat buildings
- Missing data processing (to handle missing meteorological data when a reasonable substitution cannot be made; see discussion above)

Ambient Air Quality Impact Analyses

In evaluating the impacts of the proposed project on ambient air quality, we will model the ambient impacts of the project, add those impacts to background concentrations, and compare the results to the state and federal ambient standards for SO_2, NO_2, PM_{10}, and CO. Background concentrations of NO_2 and CO will be the highest values monitored at the District's San Luis Obispo monitoring station, located approximately 13 miles southeast (downwind) of the project site, during the last three years. Background concentrations of SO_2 and PM_{10} will be the highest values monitored during the same three-year period at the District's Morro Bay monitoring station, located within approximately one mile of the project site.*

In accordance with EPA guidance (40 CFR part 51, Appendix W, Sections 11.2.3.2 and 11.2.3.3), the highest modeled concentration will be used to demonstrate compliance with annual standards while the highest second-high modeled concentrations will be used to demonstrate compliance with standards based on averaging periods of 24 hours or less.

The application will include concentration isopleths to illustrate the spatial distribution of the maximum modeled impacts from the gas turbines.

Increments Analysis

Increments are the maximum allowable increases in concentration that are allowed to occur above baseline concentrations for each pollutant for which an increment has been established: currently NO_2, SO_2, and PM_{10}. The baseline concentrations are defined for each pollutant and averaging time, and are the ambient concentrations of each pollutant existing at the time that the first complete PSD application affecting the area is submitted. Applicable significant ambient impact levels for SO_2, NO_2, and PM_{10} are shown in Table 2.

Table 2
PSD Ambient Significance Levels

Pollutant/ Avg. Period	Significance Level ($\mu g/m^3$)
SO_2 - Annual	1
- 24-hour	5
- 3-hour	25
PM_{10} - Annual	1
- 24-hour	5
NOx - Annual	1
- 1-hour	19

* SO_2 monitoring was terminated at Morro Bay at the end of 1995. Therefore, the highest concentration monitored during the last three years available will be used to represent background SO_2.

Federal regulations require increments analyses to be performed only for pollutants with ambient impacts exceeding these significance levels. According to EPA Region IX staff, it has been determined that the application for a PSD permit for the proposed modification at Morro Bay Power Plant will be the first PSD application filed in San Luis Obispo County since the PSD trigger dates. Further, based on consultations with Monterey Bay Unified APCD, Santa Barbara County APCD and San Joaquin Valley Unitifed APCD staffs, no PSD permits have been issued in those districts since the trigger date for sources that would have an annual average impact greater than 1 $\mu g/m^3$ in San Luis Obispo County. Therefore, the proposed project will set the baseline date and is the only increment-consuming source in the District. If necessary, compliance with increments will be demonstrated by comparing the ambient impacts of the project with the Class II increments.

Preconstruction Monitoring Requirements

40 CFR 52.21(m) requires an applicant's air quality analysis to contain preconstruction ambient air quality monitoring data for purposes of establishing background pollutant concentrations in the impact area of the proposed facility. Under the provisions of 40 CFR 52.21(i), however, an applicant may be exempted from the requirement for preconstruction monitoring if the predicted air quality impacts of the facility do not exceed the specified *de minimis* levels listed in Table 3. An applicant may also, at the EPA's discretion, rely on existing representative air quality monitoring data that meet EPA guidance to satisfy the requirement for preconstruction monitoring. The modeled impacts of the proposed modification are expected to be well below the *de minimis* levels, so preconstruction monitoring will not be required. The application will also include a discussion regarding the representativeness of existing background data. Information previously provided to EPA regarding the representativeness of the existing background data is attached.

Table 3
Preconstruction Monitoring Thresholds

CO: 8-hr average	575 μg/m3
PM_{10}: 24-hr average	10 μg/m3
NO_2: annual average	14 μg/m3
SO_2: 24-hr average	13 μg/m3

Additional Impacts Analysis

For those pollutants emitted in significant amounts, the applicant will prepare an additional impacts analysis for growth, soils and vegetation, and visibility. Visibility impacts will be evaluated using VISCREEN 1.01 (Version 88341).

Impacts on Class I Areas

The applicant will prepare an analysis to determine whether the proposed project will result in emissions that would have an adverse impact on air quality related values, including visibility, in nearby Class I areas. An analysis will be conducted to determine the proposed project impact on visibility at the San Rafael Wilderness in Los Padres National Forest, the nearest Class I area. Background visual range information for the San Rafael Wilderness has been obtained from the U.S. Forest Service.

A modeling analysis will also be performed to determine whether the proposed modification will result in a modeled 24-hour average impact of any pollutant of 1 $\mu g/m^3$ or more in the nearby Class I area.

GEP Stack Height

An analysis will be performed to determine the GEP heights of the new turbine stacks and to demonstrate that the heights used for modeling the stacks do not exceed GEP height.

Additional Analyses Required by the CEC

Additional analyses that may be required by the CEC are a cumulative air quality impacts analysis, an analysis of short-term impacts during turbine startups and commissioning, and an analysis of construction impacts. The procedures to be used in evaluating construction impacts are discussed below. If required, a separate protocol will be prepared for the cumulative impacts analysis.

<u>Construction Impacts Analysis</u>

The potential ambient impacts from air pollutant emissions during the construction of the Morro Bay Power Plant project will be evaluated by air quality modeling that will account for the construction site location and the surrounding topography; the sources of emissions during construction, including vehicle and equipment exhaust emissions; and fugitive dust.

<u>Site Description</u> - The proposed project will be located on the site of the existing Morro Bay Power Plant. The dispersion modeling analyses will include a description of the physical setting of the facility and surrounding terrain. A map showing the plant location, fence lines, and model receptors will be included, as well as a plot plan of the plant site indicating heights of nearby structures above a common reference point.

<u>Types of Emission Sources</u> - Construction of the proposed power plant project will be divided into three main construction phases: (1) site preparation; (2) construction of foundations; and (3) installation and assembly of mechanical and electrical equipment.

The construction impacts analysis will include a schedule for construction operation activities. Site preparation is expected to include site excavation, excavation of footings and foundations, and backfilling operations. After site preparation is finished, the construction of the foundations will begin. Once the foundations are finished, the installation and assembly of the mechanical and electrical equipment will begin.

Fugitive dust emissions from the construction of the project result from (1) dust entrained during excavation and grading at the construction site; (2) dust entrained during onsite travel on paved and unpaved roads and across the unpaved construction site; (3) dust entrained during aggregate and soil loading and unloading operations; (4) dust entrained from raw material transfer to and from material stockpiles; and (5) wind erosion of areas disturbed during construction activities. Heavy equipment exhaust emissions result from (1) exhaust from the heavy equipment used for excavation, grading, and construction of onsite structures; (2) exhaust from a water truck used to control construction dust emissions; (3) exhaust from Diesel welding machines, gasoline-powered generators, air compressors, and water pumps; and (4) exhaust from gasoline-powered pickup trucks and Diesel flatbed trucks used onsite to transport workers and materials around the construction site. Diesel and gasoline truck exhaust emissions will result from transport of mechanical and electrical equipment to the project site and transport of rubble and debris from the site to an appropriate landfill. Diesel exhaust emissions may also result from transport of raw materials to and from stockpiles.

Emissions from a worst-case day will be calculated for each of the three main construction phases and only the phase with the highest emissions will be modeled. As the construction impacts are expected to occur for a relatively short time compared with the lifetime of the project, only short-term averaging periods (24 hours or less) will be included in the construction modeling analysis.

Existing Ambient Levels - Ambient NOx, CO, and PM_{10} concentrations are monitored at two locations in the vicinity of the proposed site: Morro Bay and San Luis Obispo. These sites are believed to be representative of the site and are being proposed for use in the analyses. SO_2 was also monitored at Morro Bay through 1995. As background levels are extremely low, the 1995 data are believed to be representative of current SO_2 levels.

Model Type - The EPA-approved Industrial Source Complex Short Term (ISCST3) model will be used to estimate ambient impacts from construction emissions. The modeling options and meteorological data described above will be used for the modeling analysis.

The construction site will be represented as an area source in the modeling analysis. Emissions will be divided into two categories: exhaust emissions and dust emissions. For exhaust emissions, a plume height of 4.6 meters (15 feet) will be used. Plume height refers to the distance measured from ground level to the center line of the emissions plume. For dust emissions, a plume height of two meters will be used due to the ambient plume temperatures and negligible plume velocities.

For the construction modeling analysis, a square-shaped grid of receptors will be used with receptors spaced 60 meters apart. The grid will extend approximately 1 kilometer to the west, east, south, and north of the project site. However, receptors that would be onsite or in the ocean will be excluded. All terrain will be assumed to be at the same elevation as the facility for purposes of this construction impacts modeling analysis.

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October 21, 1999
CORRECTED

Mr. David Albright
Air Division
USEPA Region IX
75 Hawthorne Street
San Francisco, CA 94105

Re: Application for a PSD Permit
Morro Bay Power Plant

Dear Mr. Albright:

During my telephone conversation with you and Carol Bohnenkamp on October 19, 1999, you indicated that you required additional information in two areas to be able to determine that the PSD permit application filed for the Morro Bay power plant is complete. The purpose of this letter is to provide the requested information.

Preconstruction Monitoring Requirements

The comparison of modeled concentrations from the turbines with federal PSD preconstruction monitoring thresholds shown in Table 6.2-34 of the application indicates that impacts of both PM_{10} and CO exceed the preconstruction monitoring thresholds. However, the applicant believes that ambient monitoring data exist that are representative of existing air quality in the project area so that additional preconstruction monitoring is not necessary. The reasons for this are described more fully in the following paragraphs.

In general, as discussed on page 6.2-56 of the application, the preconstruction monitoring thresholds are exceeded only on Morro Rock. Maximum modeled concentrations of PM_{10} and CO are well below the thresholds in all other locations (see modeling results presented in Table 6.2-36 of the application). The wind roses presented in Figure 6.2-5 of the application show that prevailing winds in the project area are onshore winds, so existing concentrations of all pollutants on the rock, which is upwind of the City of Morro Bay and other inland urban areas, can be expected to be much lower than concentrations monitored in other locations.

To represent existing PM_{10} concentrations, the applicant proposes to use ambient PM_{10} monitoring data collected at the Morro Bay monitoring station, approximately one mile east-southeast of the power plant (see attached map for locations of plant and monitoring station). Based on the predominant onshore winds, this monitoring station is downwind of the power plant most of the time, so concentrations measured at the station would be expected to represent existing emissions from the power plant as well as PM_{10} emissions from other sources in the City of Morro Bay. The PM_{10} data presented in Table 6.2-31 of the application show that PM_{10} levels in Morro Bay are generally low: approximately 1/3 of the federal standard. The maximum monitored 24-hour concentration in 1998 (not included in the table) was 33 ug/m^3, which is lower than the concentrations monitored between 1995 and 1997. By using the 1997 monitored maximum value of 57 ug/m3 (by far the highest concentration monitored in Morro Bay over the past four years), the applicant believes that the background concentrations of PM_{10} in the vicinity of the project are being conservatively overestimated.

Further, a comparison of the 1997 and 1998 monitored PM_{10} concentrations in other nearby locations indicate that PM_{10} concentrations in the region remain well below the federal standard. This comparison is shown in Table 1 below. Therefore, the addition of the proposed project would not be expected to bring ambient PM_{10} levels anywhere near the national ambient air quality standard.

Table 1
Monitored 24-Hour Average PM_{10} Concentrations
in the Vicinity of Morro Bay Power Plant

Monitoring Station	Calendar Year		Distance/Direction from Morro Bay Power Plant (mi)
	1997	1998	
Morro Bay	57	33	~1 (ESE)
San Luis Obispo	55	27	~13 (SE)
Atascadero	70	38	~13 (NE)

To represent background concentrations of carbon monoxide, the applicant proposes to use ambient CO data collected by the California Air Resources Board at the San Luis Obispo monitoring station approximately 13 miles southeast of the power plant. As shown in Table 2, carbon monoxide in San Luis Obispo County comes predominantly from areawide sources, including mobile sources, residential fuel combustion, waste burning and disposal, and wildfires. Stationary, or point, sources of emissions account for less than one percent of the inventory. Thus, CO levels monitored in a more developed area, such as San Luis Obispo, would be expected to be higher than CO levels monitored in a smaller, less developed area such as Morro Bay. The concentration of CO-producing sources, including on-road motor vehicles, residential fuel consumption, and waste burning and disposal, would be expected to be higher in San Luis Obispo (which is near heavily traveled Highways 101 and 1 and had a 1998 population of 42, 650) than in Morro Bay (which is upwind of Highway 1 and had a 1998 population of 9,850). Therefore, the ambient CO levels monitored in San Luis Obispo are believed to conservatively overestimate ambient CO levels that would be found in the vicinity of the project.

Table 2 1996 Emission Inventory, San Luis Obispo County		
Inventory Category	CO Emissions, tons per day	Percent of Total Inventory
Fuel Combustion	1.1	0.6%
All Stationary Sources	1.1	0.6%
Residential Fuel Combustion	11.1	5.8%
Waste Burning and Disposal	23.8	12.5%
Utility Equipment	6.4	3.4%
All Areawide Sources	41.4	21.8%
Light-Duty Passenger Cars and Trucks	88.7	46.6%
All Mobile Sources	126.2	66.3%
Wildfires	21.6	11.4%
All Natural Sources	21.6	11.4%
Total, All Sources	190.3	100%

Source: ARB website.

Impacts of Project-Induced Growth

The federal PSD regulations (40 CFR 52.21 (o) (2)) require an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial, and other growth associated with the proposed modification. The discussion of socioeconomic impacts of the proposed project (Section 6.10 of the AFC) indicates that the project will create no new permanent jobs or secondary employment in the region and will have no significant impact on tourism. Therefore, no commercial, residential, or industrial growth is expected as a result of the proposed modification, and no associated air quality impacts are projected for the area.

I hope that this provides the additional information you need to determine that the PSD application is complete. If you have any questions regarding this information, or regarding any other aspect of the project, please do not hesitate to call.

Sincerely,

Nancy Matthews

Nancy Matthews

cc: Carol Bohnenkamp, EPA Region IX
Mark Seedall, Duke Energy
Mark Hays, Duke Energy
Jane Luckhardt, Downey Brand
Chris Ellison, Ellison & Schneider

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November 29, 1999

Mr. Matt Haber
Chief, Permits Office
Air Division
USEPA Region IX
75 Hawthorne Street
San Francisco, CA 94105

Re: Application for a PSD Permit
Morro Bay Power Plant

Dear Mr. Haber:

This letter is written in response to your letter dated October 27, 1999, and discussions during our November 4, 1999, meeting with you, David Albright, and Carol Bohnenkamp in which you requested additional information about CO emissions sources and other factors that will allow you to fully evaluate the representativeness of the CO ambient air quality data used in the application for a Prevention of Significant Deterioration permit for a major modification at the Morro Bay Power Plant in Morro Bay, California.

Preconstruction monitoring requirements for PM_{10} were addressed in our October 21, 1999, letter to David Albright. The representativeness of existing monitoring data for use in characterizing existing air quality in the CO impact area is discussed in more detail here.

Location of the CO Impact Area

As discussed in our October 21, 1999, letter regarding preconstruction monitoring requirements for the project, we indicated that the preconstruction monitoring thresholds are exceeded only on Morro Rock. The attached figure (Figure 6.11-2 of the AFC) shows the location of Morro Rock relative to the power plant: the rock is approximately three-quarters of a mile west-southwest of the plant. While the beach area leading up to and around Morro Rock is accessible to the public, the rock itself is an ecological preserve serving as a nesting area for Peregrine falcons to which public access is prohibited. Therefore, there can actually be no public exposure in the location where the preconstruction monitoring threshold is exceeded.

Prevailing winds in Morro Bay are from the west and the west-northwest during most of the year and from the northeast and east-northeast during the winter months. Therefore, Morro Rock is upwind of all emissions sources most of the year. The Rock is downwind of the city of Morro Bay during the winter months. The terrain immediately surrounding the power plant site is fairly flat. The Chorro Creek Valley climbs slowly inland from just SE of the town of Morro Bay. Low hills lie to the north of the creek, and several prominent peaks can be found along Park Ridge, which lies just south of the creek. Besides Morro Rock, the nearest terrain that is above HRSG final plume rise is the westernmost of the peaks along Park Ridge—namely, Black Hill—nearly 3 km southeast of the facility. Nearby terrain features do not surround the power plant facility sufficiently to trap pollutants emitted from the town of Morro Bay or the power plant: air is generally free to move up and down the Chorro Creek Valley.

Characterization of the Ambient CO Data Collected in San Luis Obispo

The Air Resources Board collects ambient CO data at 1160 Marsh Street in San Luis Obispo. The location of the monitoring station is shown in the attached figure. The area in which the monitor is located is a commercial area, east of U.S. 101, with residential areas to the north and south. As shown in the attached wind roses for the monitoring site, prevailing winds at that location are from the north through the west. Therefore, CO concentrations monitored there are representative of the on-road vehicle traffic and residential and commercial activity in the surrounding area.

Ambient CO Impacts in Morro Bay

As shown in the attached summary of the 1996 emission inventory for San Luis Obispo County, CO emissions in the county are primarily from area and mobile sources. There are very few large point sources of emissions (shown as "stationary sources" in the inventory listing) in the county; Morro Bay Power Plant is one of these. These point sources of emissions account for less than 1% of the CO emissions in the county. The rest of the emissions come from very small, dispersed sources that are associated with human activity. For example, area sources, including residential fuel combustion, waste burning and disposal, and utility equipment (such as lawn mowers) account for a little over 20% of CO emissions. These emissions will occur mainly in residential areas, so CO emissions from these sources will be concentrated around residential areas. Areas with larger populations will therefore tend to have more CO emissions—and thus, higher ambient concentrations of CO from these sources—than areas with smaller populations.

The other major source of CO emissions in San Luis Obispo County is mobile sources, which account for 66% of total emissions. Most of these emissions (98 out of 126 tons) come from on-road motor vehicles, including automobiles and trucks. Again, areas of higher vehicle activity (that is, more vehicle miles traveled) will tend to have higher CO emissions than areas with less vehicle activity.

The other 11% of CO emissions in the county are attributed to wildfires. Wildfires occur throughout the undeveloped portion of the county, and the population centers are concentrated along U.S. 101 and Highway 1. Therefore CO emissions from wildfires probably occur mostly in the mountainous eastern portion of the county and do not contribute to ambient CO concentrations in the project area.

In summary, the sources of CO in Morro Bay are residential, commercial, and motor vehicle activity, plus the existing Morro Bay Power Plant. Because prevailing winds in Morro Bay are from the west most of the year, most of the time there are no upwind sources of CO, and CO concentrations monitored in the impact area would be expected to be close to zero. During the winter months when the prevailing winds are from the east, CO concentrations in the impact area would be influenced by the upwind sources described above. With the exception of the Morro Bay Power Plant, these sources are similar in type, although much smaller in number, than the sources in the vicinity of the San Luis Obispo ambient monitoring station. Therefore, CO concentrations monitored at San Luis Obispo, a more developed and populated area, can be expected to be similar to and probably somewhat higher than CO concentrations that would be monitored in the impact area with the exception of the contribution of the Morro Bay Power Plant. The modeled maximum project impacts presented in Table 6.2.32 of the PSD application include both the existing boilers and the new gas turbines. Therefore, we believe that the use of the monitored CO background data from San Luis Obispo, in combination with the modeling analysis presented in the PSD application, accurately characterizes the worst-case ambient concentrations of CO with the project in operation. This worst-case analysis demonstrates that total ambient CO impacts with the project are well below the federal CO ambient standards.

I hope that this provides adequate technical information to allow you to determine that the ambient CO data collected at San Luis Obispo can be used to represent background CO levels for the Morro Bay Power Plant project. If you have any questions or require additional information, please do not hesitate to call.

Sincerely,

Nancy Matthews

Nancy Matthews

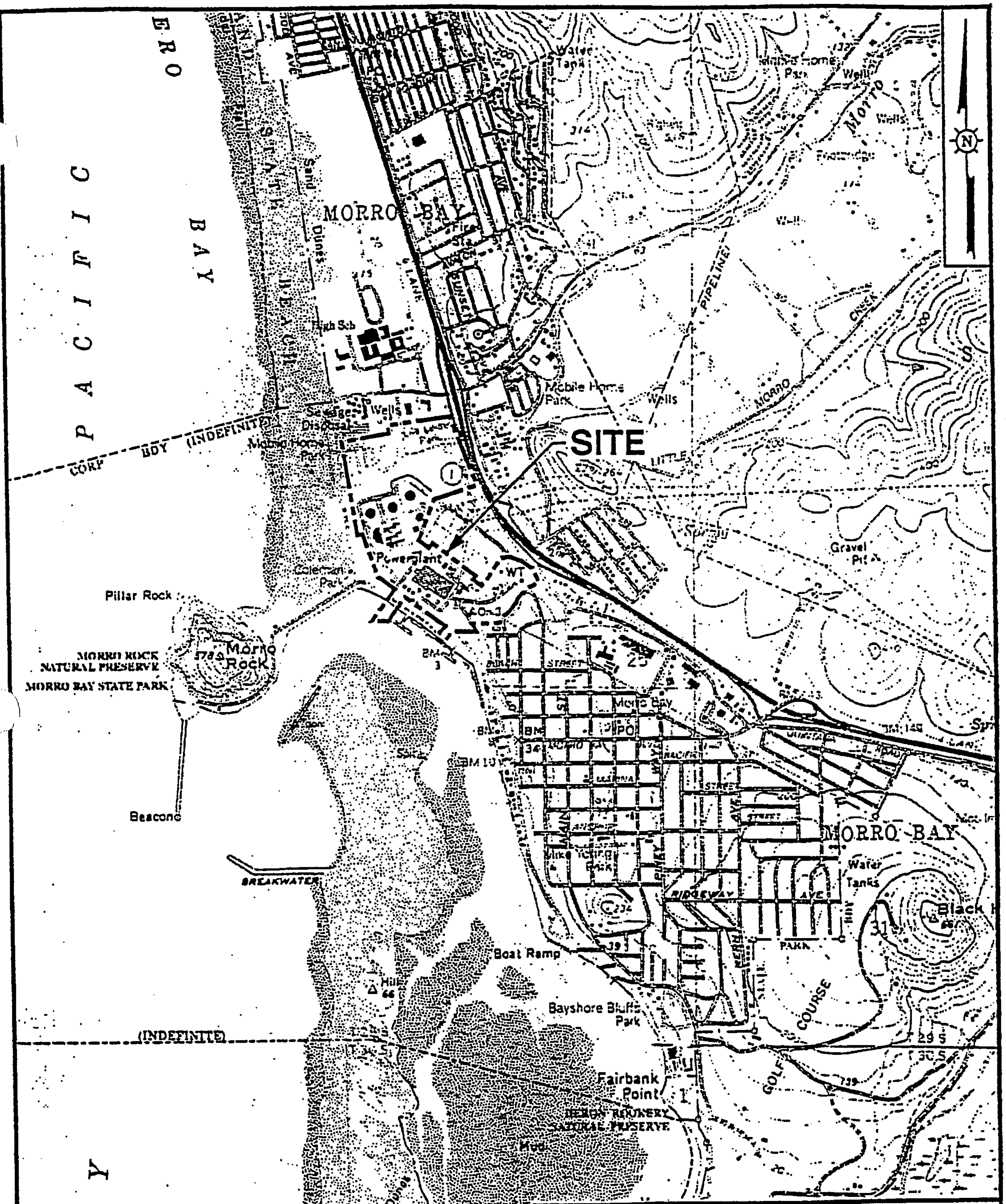
attachments

cc: Carol Bohnenkamp, EPA Region IX
David Albright, EPA Region IX
Mark Seedall, Duke Energy
Mark Hays, Duke Energy
Gary Willey, San Luis Obispo County APCD
Ray Menebroker, ARB

Attachment 1

Location of Morro Rock Relative to Power Plant Site
(Figure 6.11-2 of the AFC)

98-.05 REV. 6/15/99



0 2,000 4,000 FEET

SCALE

SCALE: 1: 24,000

REFERENCE: USGS 7.5 MINUTE TOPOGRAPHIC MAP OF MORRO BAY NORTH AND MORRO BAY SOUTH, CALIFORNIA, DATED 1993 AND 1994.

MORRO BAY AREA MAP

DUKE ENERGY MORRO BAY LLC
MORRO BAY POWER PLANT

TRC

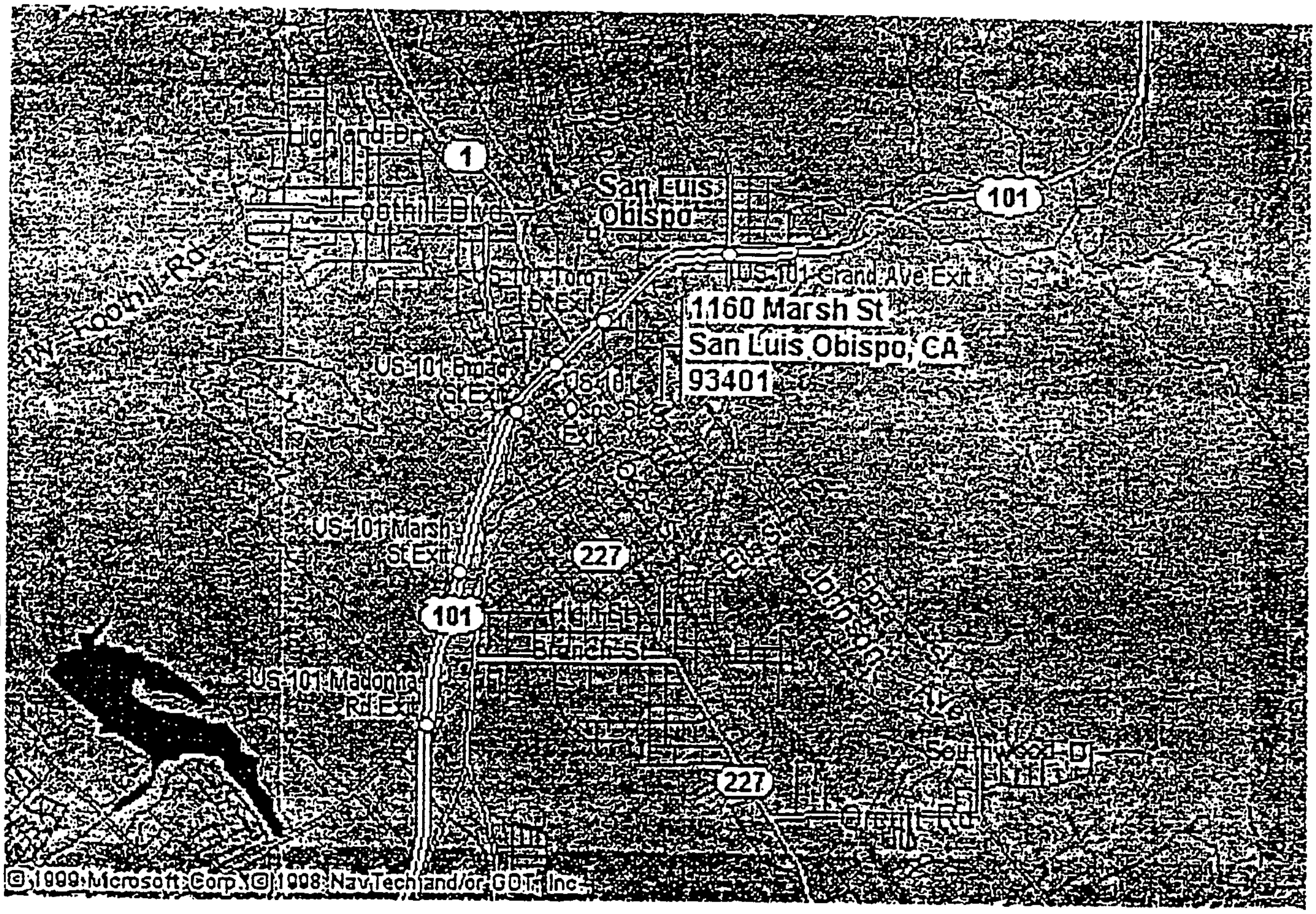
FIGURE 6.11-2

Attachment 2

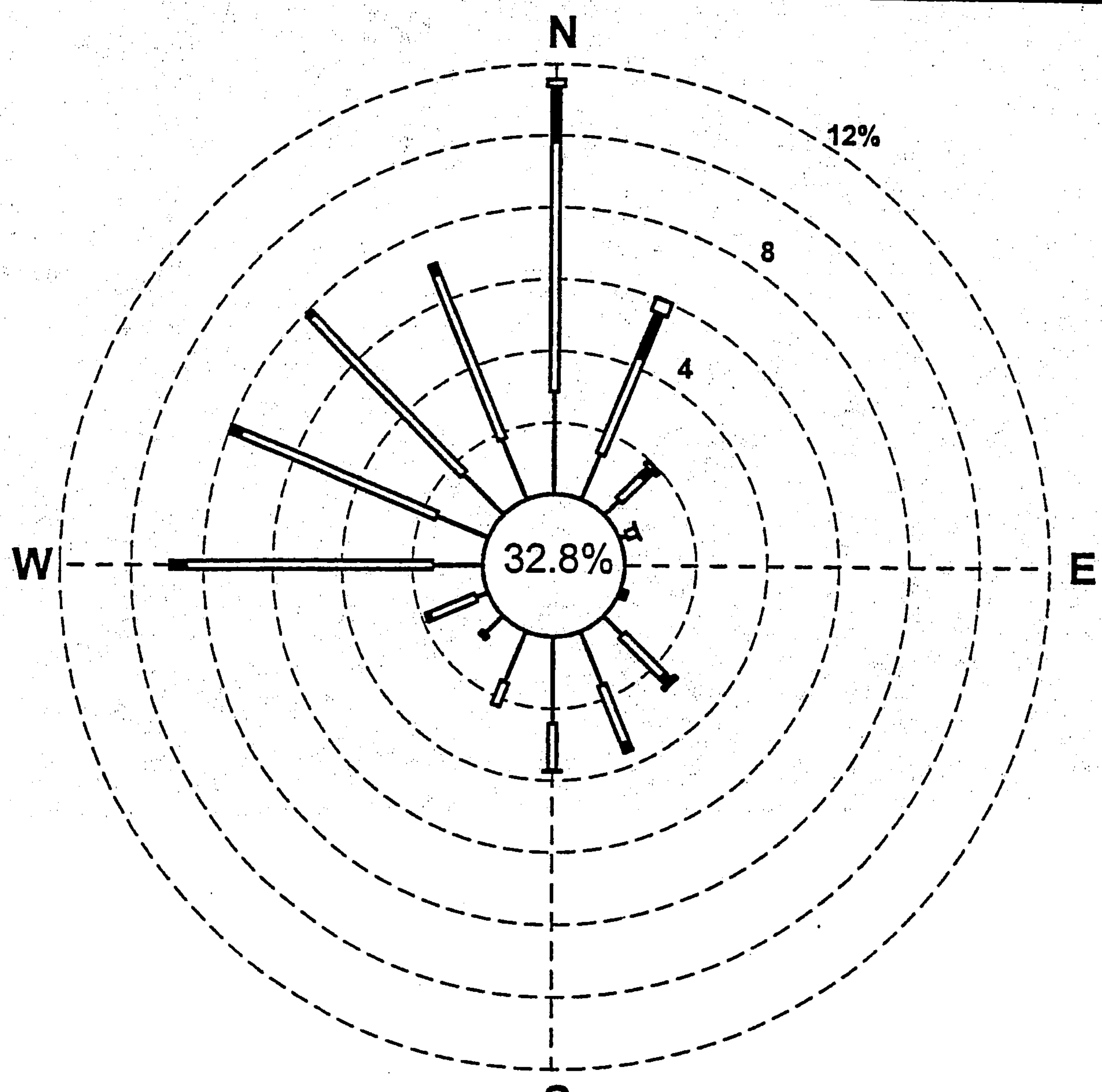
Map Showing Location of ARB's San Luis Obispo Ambient Monitor

Wind Roses for the San Luis Obispo Site

Location of San Luis Obispo Ambient Monitoring Station



San Luis Obispo - Marsh - 1995
January 1, 1995 through December 31, 1995



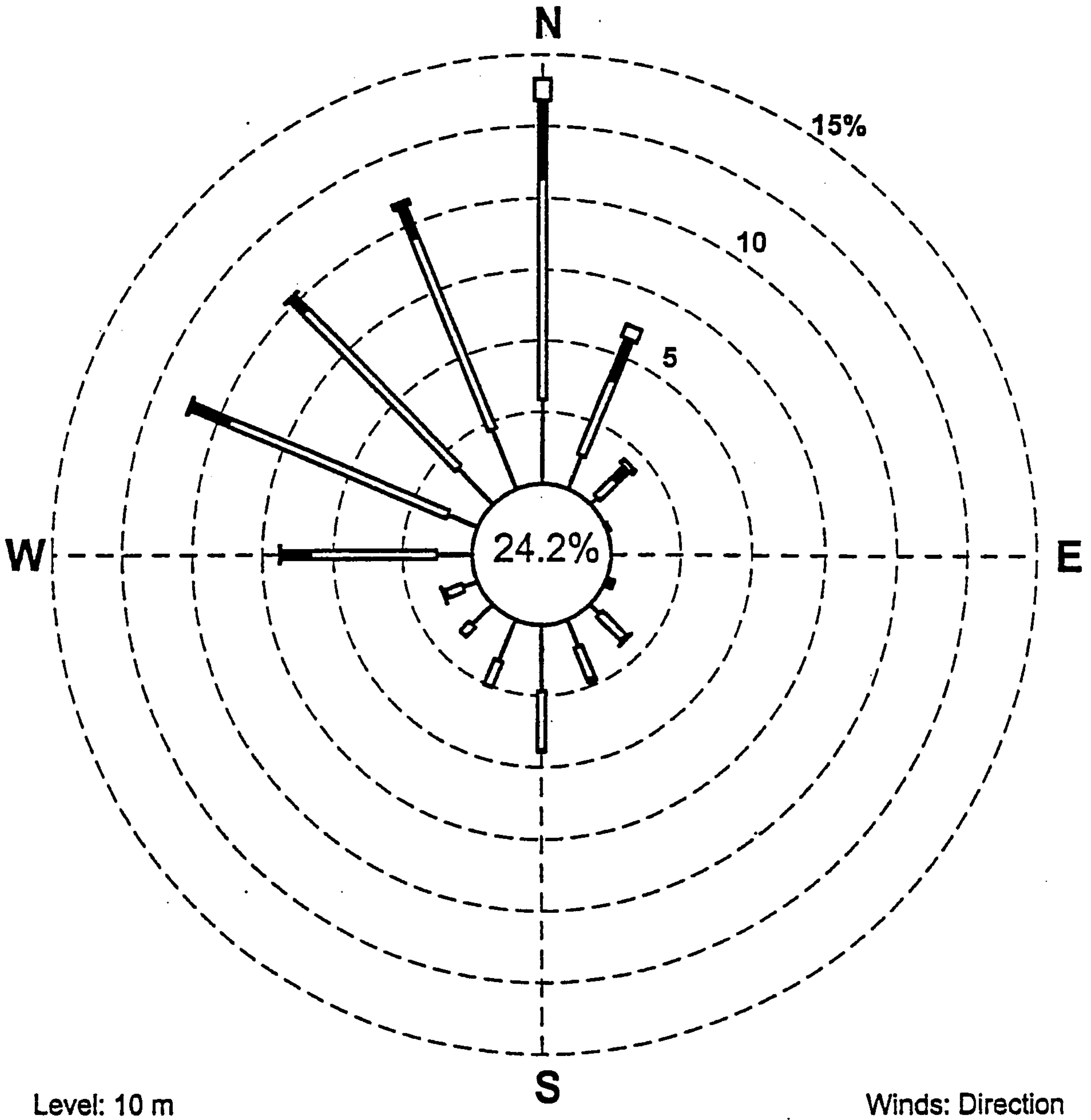
Level: 10 m

Winds: Direction

1.01 to 1.54
3.09 to 5.14
8.23 to 10.8
1.54 to 3.09
5.14 to 8.23
>= 10.8 (m/s)

Number of Records Used: 8760

San Luis Obispo - Marsh - 1997
January 1, 1997 through December 31, 1997

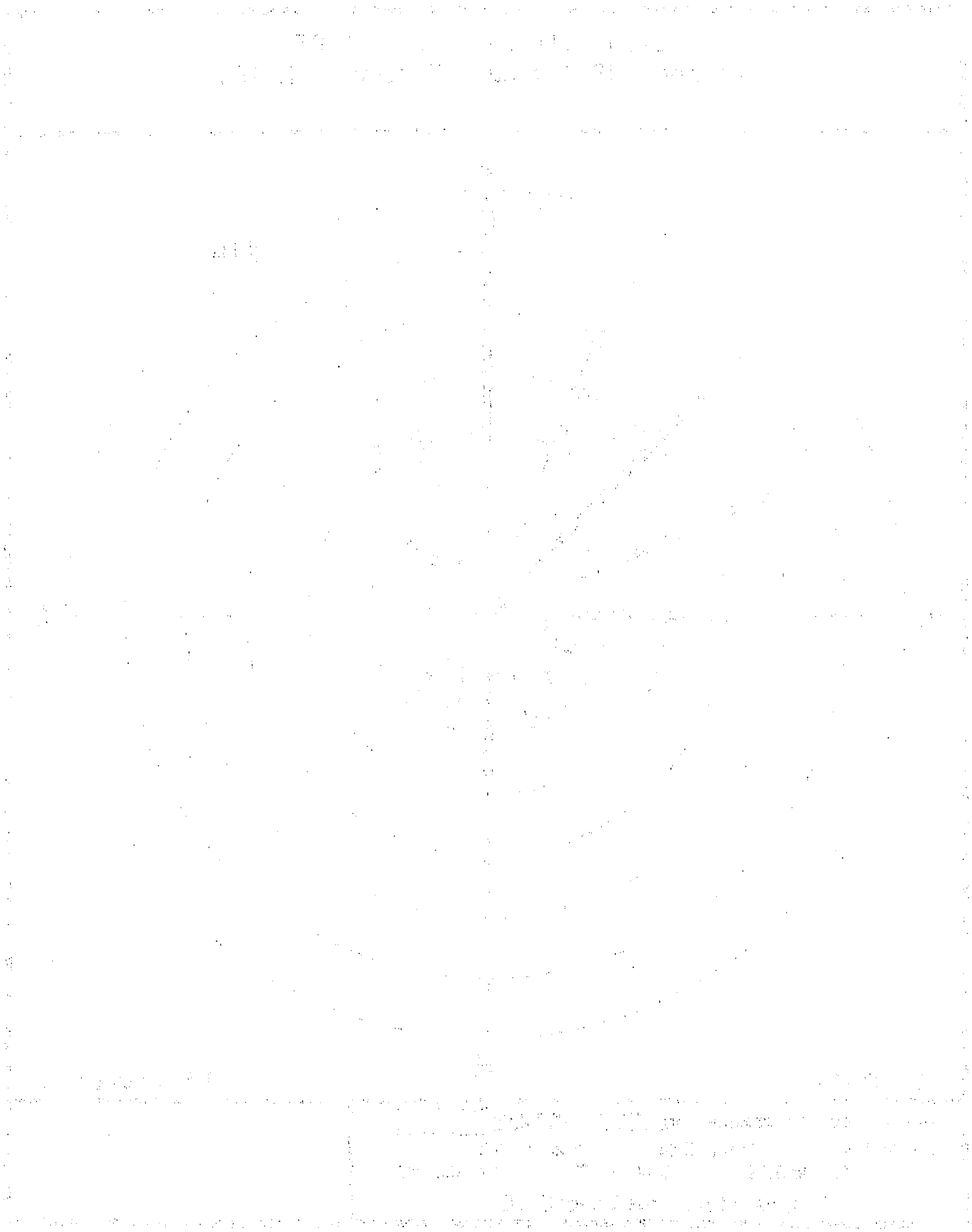


Level: 10 m

Winds: Direction

1.01 to 1.54
3.09 to 5.14
8.23 to 10.8
1.54 to 3.09
5.14 to 8.23
>= 10.8 (m/s)

Number of Records Used: 8760



Attachment 3

Summary of 1996 Emission Inventory for San Luis Obispo County

1996 Emission Inventory
San Luis Obispo County

SRC_TYPE	CATEGORY	SUBCATEGORY	Emissions, tons/day			Emissions as % of Total		
			NOx	CO	PM10	NOx	CO	PM10
STATIONARY	FUEL COMBUSTION	ELECTRIC UTILITIES	1.9	0.6	0.2			
		COGENERATION	0.1	0.1	0			
		OIL AND GAS PRODUCTION (COMBUSTION)	0.5	0.1	0			
		PETROLEUM REFINING (COMBUSTION)	0.2	0.1	0			
		MANUFACTURING AND INDUSTRIAL	0.2	0.1	0			
		FOOD AND AGRICULTURAL PROCESSING	0	0	0			
		SERVICE AND COMMERCIAL	0.7	0.1	0			
		OTHER (FUEL COMBUSTION)	0	0	0			
		Subtotal, Fuel Combustion	3.6	1.1	0.2			
	WASTE DISPOSAL	SEWAGE TREATMENT	0	0	0			
		LANDFILLS	0	0	0			
		INCINERATORS	0	0	0			
		SOIL REMEDIATION	0	0	0			
		OTHER (WASTE DISPOSAL)	0	0	0			
		Subtotal, Waste Disposal	0	0	0			
	CLEANING/SURFACE CTGS	LAUNDERING	0	0	0			
		DEGREASING	0	0	0			
		COATINGS AND RELATED PROCESS SOLVENTS	0	0	0			
		PRINTING	0	0	0			
		OTHER (CLEANING AND SURFACE COATINGS)	0	0	0			
		Subtotal, Cleaning/Surface Ctg	0	0	0			
	PETROLEUM PRODUCTION A	OIL AND GAS PRODUCTION	0	0	0			
		PETROLEUM REFINING	0.1	0	0			
		PETROLEUM MARKETING	0.1	0	0.4			
		OTHER (PETROLEUM PRODUCTION AND MARKETING)	0	0	0			
		Subtotal, Petroleum Production	0.2	0	0.4			
	INDUSTRIAL PROCESSES	CHEMICAL	0	0	0			
		FOOD AND AGRICULTURE	0	0	0.1			
		MINERAL PROCESSES	0	0	0.4			
		METAL PROCESSES	0	0	0			
		WOOD AND PAPER	0	0	0			
		GLASS AND RELATED PRODUCTS	0	0	0			
		ELECTRONICS	0	0	0			
		OTHER (INDUSTRIAL PROCESSES)	0	0	0			
		Subtotal, Industrial Processes	0	0	0.5			
	Subtotal, Stationary Sources		3.8	1.1	1.1	11.8%	0.6%	3.4%
AREA-WIDE	SOLVENT EVAPORATION	CONSUMER PRODUCTS	0	0	0			
		ARCHITECTURAL COATINGS AND RELATED PROCESS SOLVENTS	0	0	0			
		PESTICIDES/FERTILIZERS	0	0	0			
		ASPHALT PAVING	0	0	0			
		REFRIGERANTS	0	0	0			
		OTHER (SOLVENT EVAPORATION)	0	0	0			
		Subtotal, Solvent Evaporation	0	0	0			

1996 Emission Inventory
San Luis Obispo County

SRC_TYPE	CATEGORY	SUBCATEGORY	Emissions, tons/day NOx	CO	PM10	Emissions as % of Total NOx	CO	PM10
	MISCELLANEOUS PROCESSE	RESIDENTIAL FUEL COMBUSTION	0.7	11.1	1.6			
		FARMING OPERATIONS	0	0	2			
		CONSTRUCTION AND DEMOLITION	0	0	4.4			
		PAVED ROAD DUST	0	0	3.9			
		UNPAVED ROAD DUST	0	0	9.5			
		FUGITIVE WINDBLOWN DUST	0	0	1.7			
		FIRES	0	0.1	0			
		WASTE BURNING AND DISPOSAL	0	23.8	3.2			
		UTILITY EQUIPMENT	0	6.4	0			
		OTHER (MISCELLANEOUS PROCESSES)	0	0	0.1			
		Subtotal, Misc. Processes	0.7	41.4	26.4			
	Subtotal, Areawide Sources		0.7	41.4	26.4	2.2%	21.8%	82.5%
MOBILE	ON-ROAD MOTOR VEHICLES	LIGHT DUTY PASSENGER (LDA)	5.9	55.4	0.1			
		LIGHT AND MEDIUM DUTY TRUCKS	0	0	0			
		LIGHT DUTY TRUCKS - 1 (LDT1)	4.8	33.3	0.1			
		MEDIUM DUTY TRUCKS (MDV)	0.7	3.2	0			
		HEAVY DUTY GAS TRUCKS (ALL)	0	0	0			
		LIGHT HEAVY DUTY GAS TRUCKS 1 (LHDV1)	0.8	2.1	0			
		MEDIUM HEAVY DUTY GAS TRUCKS (MHDV)	0.3	1.1	0			
		HEAVY DUTY DIESEL TRUCKS (ALL)	0	0	0			
		LIGHT HEAVY DUTY DIESEL TRUCKS - 1 (LHDV1)	0.4	0.3	0			
		MEDIUM HEAVY DUTY DIESEL TRUCKS (MHDV)	1	0.6	0.1			
		HEAVY HEAVY DUTY DIESEL TRUCKS (HHDV)	3.1	1.6	0.2			
		MOTORCYCLES (MCY)	0.1	0.4	0			
		HEAVY DUTY DIESEL URBAN BUSES (UB)	0	0	0			
		OTHER (ON-ROAD MOTOR VEHICLES)	0	0	0			
		Subtotal, On-road Motor Vehicles	17.1	98	0.5	52.9%	51.5%	1.6%
	OTHER MOBILE SOURCES	AIRCRAFT	0.1	5.3	0			
		TRAINS	2.4	0.3	0			
		SHIPS AND COMMERCIAL BOATS	1.2	0.2	0.1			
		RECREATIONAL BOATS	0.1	5.3	0.1			
		OFF-ROAD RECREATIONAL VEHICLES	0	1.6	0			
		COMMERCIAL/INDUSTRIAL MOBILE EQUIPMENT	1.8	3.6	0.1			
		FARM EQUIPMENT	4.8	11.9	0.3			
		OTHER (OTHER MOBILE SOURCES)	0	0	0			
		Subtotal, Other Mobile Sources	10.4	28.2	0.6			
	Subtotal, Mobile Sources		27.5	126.2	1.1	85.1%	66.3%	3.4%
NATURAL (NON-ANTHROPOGENIC)	NATURAL SOURCES	GEOGENIC SOURCES	0	0	0			
		WILDFIRES	0.3	21.6	3.4			
		WINDBLOWN DUST	0	0	0			
		OTHER (NATURAL SOURCES)	0	0	0			
		Subtotal, Natural Sources	0.3	21.6	3.4			
	Subtotal, Natural Sources		0.3	21.6	3.4	0.9%	11.4%	10.6%
Total, All Sources			32.3	190.3	32.0			

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July 31, 2000

Larry Allen, Supervisor
Planning Section
San Luis Obispo County
Air Pollution Control District
3433 Roberto Court
San Luis Obispo, CA 93401

Re: Modeling Protocol for Morro Bay Power Plant Application for Certification

Dear Larry:

During our telephone conversation on Friday, July 28, we discussed the revised protocol for evaluating ambient air quality impacts of the proposed modifications at Duke Energy's Morro Bay Power Plant. You requested several additions and clarifications to the protocol. The purpose of this letter is to confirm our understanding of the requested additions and clarifications to ensure that the modeling analysis in the AFC provides all of the information needed by the District staff to evaluate the proposed project.

You pointed out that the protocol addresses the proposed new equipment at the power plant, but does not cover the existing plant. We confirmed that the AFC would include a modeling analysis and a screening health risk assessment of the existing plant and that the existing standby generators will be included in the assessment of existing and future plant impacts.

We discussed the need for an analysis of fog effects on dispersion and acid deposition. To address the first issue, we will identify worst-case impacts under meteorological conditions that lead to fog formation and compare these to overall worst-case impacts. To address the second issue, we are investigating approaches for modeling the conversion of NOx and SO_2 emissions to nitrates and sulfates under conditions of persistent fog to address public concerns regarding acid deposition.

We confirmed that the ISCST3 modeling would include complex terrain receptors. Ambient ozone impacts will be evaluated using the ISC_OLM model and concurrent ozone data from the Morro Bay monitoring station.

We indicated in the protocol that the highest modeled concentration would be used to demonstrate compliance with annual standards, while the highest second-high concentrations would be used to demonstrate compliance with short-term standards. You indicated that compliance with state short-term standards would need to be demonstrated using the highest modeled concentrations for District purposes.

For the construction impacts analysis we agreed with your recommendation that our receptor grid be spaced at 30 meters, rather than 60 meters. We also agreed that the construction impacts analysis would use actual receptor heights instead of the proposed assumption that all terrain elevations are equal to the facility elevation.

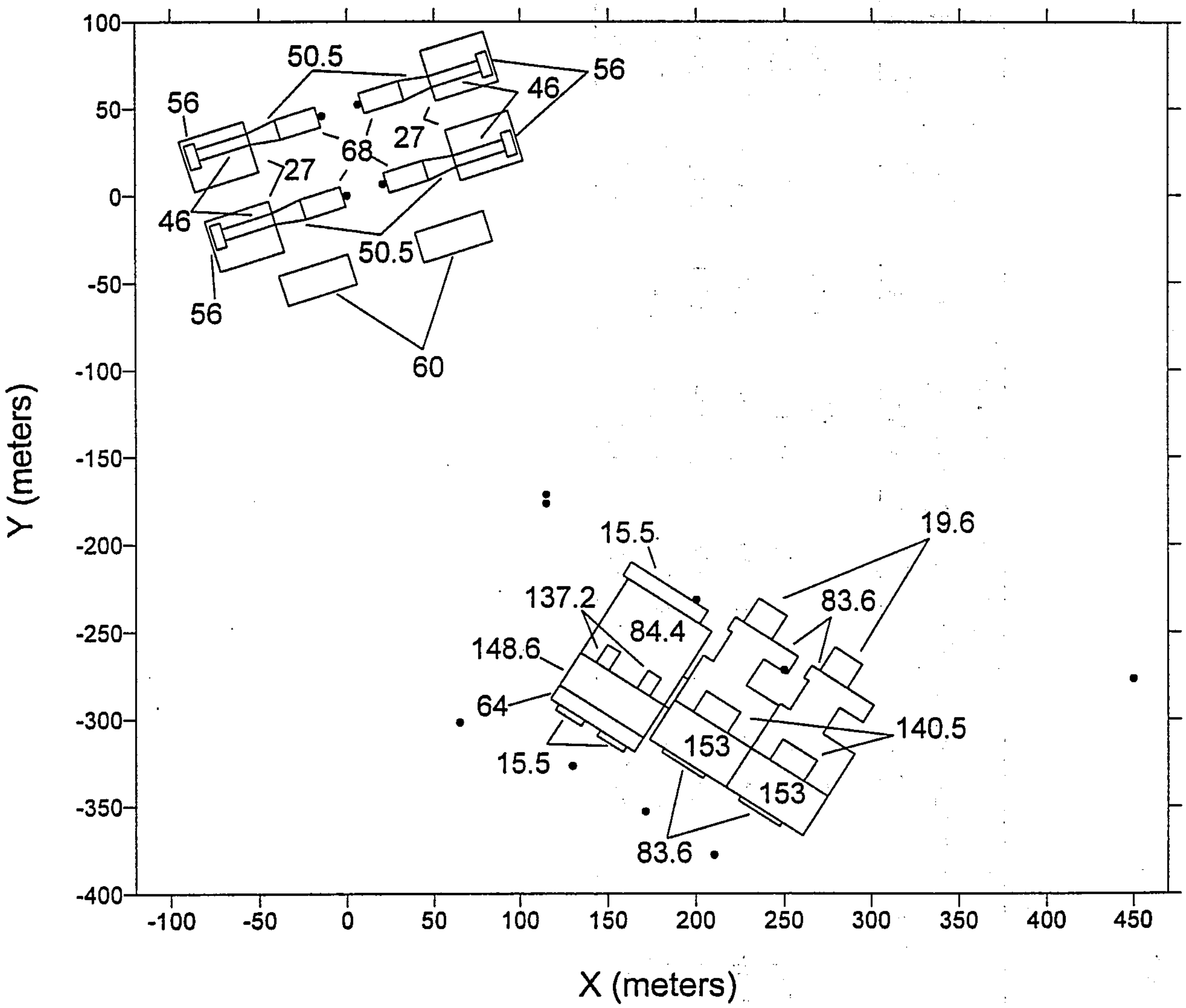
We appreciate your review and comments on the revised protocol. If you have any additional questions or clarifications, please do not hesitate to call.

Sincerely,

Gary Rubenstein

cc: Gary Willey, SLOCAPCD
Mark Hays, Duke Morro Bay
Bob Cochran, Duke Morro Bay
Andy Trump, DEPS
Matthew Layton, CEC
David Albright, USEPA Region IX

Figure 6.2-2.1
Building Dimensions Used in GEP Analysis



NOTE: Building heights are shown in feet.

Table 6.2-2.1
Emissions and Stack Parameters for Screening Modeling
New Turbines

Turbine Case	Load/ Ambient Temp	Duct Firing?	Stack Diam (m)	Stack Height (m)	Exhaust Temp (deg K)	Exhaust Velocity (m/s)	NOx, g/s	SO2, g/s	CO, g/s	PM10, g/s
1	100/85F	no	5.486	44.196	359.111	18.520	1.877	0.146	2.746	1.386
2	100/85F	yes	5.486	44.196	353.556	18.410	2.363	0.183	3.454	1.671
3	50/85F	no	5.486	44.196	344.111	12.129	1.229	0.095	1.793	1.386
4	100/34F	no	5.486	44.196	362.444	20.774	2.107	0.164	3.076	1.386
5	100/34F	yes	5.486	44.196	358.000	20.641	2.434	0.189	3.561	1.501
6	50/34F	no	5.486	44.196	345.222	11.956	1.242	0.097	1.814	1.386

Table 6.2-2.2
Results of the Turbine Screening Analysis

Case	Temp/Load	Duct Firing?	Modeled Impacts, ug/m3, by Pollutant and Averaging Period										
			NOx		SO2				CO		PM10		
			1-hr	Annual	1-hr	3-hr	24-hr	Annual	1-hr	8-hr	24-hr	Annual	
1994 Meteorological Data													
1	100/85F	no	170.40	2.54	13.3	8.31	1.80	0.20	249.2	91.9	17.1	1.87	
2	100/85F	yes	223.20	3.30	17.3	10.7	2.32	0.26	326.3	119.8	21.2	2.33	<=max x ann. PM10
3	50/85F	no	133.00	2.27	10.3	6.36	1.41	0.18	194.0	77.5	20.6	2.55	<=max ann. PM10
4	100/34F	no	182.60	2.66	14.2	8.86	1.92	0.21	266.6	94.5	16.3	1.75	
5	100/34F	yes	215.30	3.15	16.7	10.4	2.25	0.24	315.0	112.8	17.9	1.94	
6	50/34F	no	134.30	2.29	10.5	6.49	1.44	0.18	196.2	78.4	20.6	2.55	
1995 Meteorological Data													
1	100/85F	no	169.6	2.32	13.2	9.34	2.18	0.18	248.1	87.4	20.7	1.71	
2	100/85F	yes	220.4	2.02	17.1	11.88	2.81	0.23	322.1	113.5	25.6	2.14	<=max x ann. PM10
3	50/85F	no	133.6	2.14	10.3	7.21	1.70	0.17	194.9	70.9	24.8	2.41	<=max ann. PM10
4	100/34F	no	181.3	2.39	14.1	10.04	2.29	0.19	264.7	90.2	19.4	1.57	
5	100/34F	yes	213.1	2.83	16.6	11.81	2.71	0.22	311.8	107.8	21.5	1.75	
6	50/34F	no	134.9	2.16	10.5	7.36	1.73	0.17	197.1	71.7	24.8	2.41	
1996 Meteorological Data													
1	100/85F	no	166.3	2.15	12.9	8.66	1.87	0.17	243.3	99.3	17.8	1.59	
2	100/85F	yes	215.6	2.79	16.7	11.05	2.43	0.22	315.2	129.1	22.2	1.97	<=max x ann. PM10 (1)
3	50/85F	no	129.8	1.89	10.0	6.75	1.59	0.15	189.3	82.1	23.2	2.13	<=max ann. PM10
4	100/34F	no	176.9	2.26	13.8	9.18	2.00	0.18	258.2	102.6	16.9	1.49	
5	100/34F	yes	208.6	2.67	16.2	10.81	2.35	0.21	305.2	122.0	18.7	1.65	
6	50/34F	no	131.1	1.91	10.2	6.89	1.62	0.15	191.5	83.1	23.2	2.13	

Note 1: Although Cases 3 and 6 have higher 24-hour average PM10 impacts than Case 2 using the 1996 met data, Case 2 using the 1995 met data has highest impacts.

Table 6.2-2.3
Emission Rates and Stack Parameters for Modeling
Boilers 1, 2, 3 and 4

	Stack Diam, m	Stack Height, m (1)	Exhaust Temp, Deg K	Exhaust Flow, m3/s	Exhaust Velocity, m/s	Emission Rate, g/s			
						NOx	SO2	CO	PM10
Averaging Period: One hour									
Boilers 1&2	4.51	116.74	398.0	523.2	32.7	47.24	0.25	11.13	n/a
Boiler 3	4.32	116.74	398.0	450.0	30.7	12.09	0.26	43.88	n/a
Boiler 4	4.32	116.74	398.0	450.0	30.7	14.41	0.26	41.14	n/a
Averaging Period: Three hours									
Boilers 1&2	4.51	116.74	398.0	523.2	32.7	n/a	0.25	n/a	n/a
Boiler 3	4.32	116.74	398.0	450.0	30.7	n/a	0.26	n/a	n/a
Boiler 4	4.32	116.74	398.0	450.0	30.7	n/a	0.26	n/a	n/a
Averaging Period: Eight hours									
Boilers 1&2	4.51	116.74	398.0	523.2	32.7	n/a	n/a	11.13	n/a
Boiler 3	4.32	116.74	398.0	450.0	30.7	n/a	n/a	43.88	n/a
Boiler 4	4.32	116.74	398.0	450.0	30.7	n/a	n/a	41.14	n/a
Averaging Period: 24 hours									
Boilers 1&2	4.51	116.74	398.0	523.2	32.7	n/a	0.25	n/a	3.18
Boiler 3	4.32	116.74	398.0	450.0	30.7	n/a	0.26	n/a	3.27
Boiler 4	4.32	116.74	398.0	450.0	30.7	n/a	0.26	n/a	3.27
Averaging Period: Annual									
Boilers 1&2	4.51	116.74	398.0	523.2	32.7	9.77	0.05	n/a	0.65
Boiler 3	4.32	116.74	398.0	450.0	30.7	4.28	0.09	n/a	1.16
Boiler 4	4.32	116.74	398.0	450.0	30.7	5.37	0.10	n/a	1.22

Note 1: Boiler stack physical heights are 450 ft; however, they are GEP-limited to 383 ft (116.74 m) for modeling purposes. See text (Section 6.2.6.3.1).

Table 6.2-2.4
Emission Rates and Stack Parameters for Modeling
Gas Turbines

	Stack Diam, m	Stack Height, m	Exh Temp, Deg K	Exhaust Flow, m3/s	Exhaust Velocity, m/s	Emission Rate, g/s NOx	SO2	CO	PM10
Averaging Period: One hour									
Turbine 1/HRSG	5.49	44.20	353.6	435.2	18.41	2.363	0.183	3.454	n/a
Turbine 2/HRSG	5.49	44.20	353.6	435.2	18.41	2.363	0.183	3.454	n/a
Turbine 3/HRSG	5.49	44.20	353.6	435.2	18.41	2.363	0.183	3.454	n/a
Turbine 4/HRSG	5.49	44.20	353.6	435.2	18.41	2.363	0.183	3.454	n/a
Averaging Period: Three hours									
Turbine 1/HRSG	5.49	44.20	353.6	435.2	18.41	n/a	0.183	n/a	n/a
Turbine 2/HRSG	5.49	44.20	353.6	435.2	18.41	n/a	0.183	n/a	n/a
Turbine 3/HRSG	5.49	44.20	353.6	435.2	18.41	n/a	0.183	n/a	n/a
Turbine 4/HRSG	5.49	44.20	353.6	435.2	18.41	n/a	0.183	n/a	n/a
Averaging Period: Eight hours									
Turbine 1/HRSG	5.49	44.20	353.6	435.2	18.41	n/a	n/a	40.79	n/a
Turbine 2/HRSG	5.49	44.20	353.6	435.2	18.41	n/a	n/a	39.92	n/a
Turbine 3/HRSG	5.49	44.20	353.6	435.2	18.41	n/a	n/a	40.79	n/a
Turbine 4/HRSG	5.49	44.20	353.6	435.2	18.41	n/a	n/a	39.92	n/a
Averaging Period: 24 hours									
Turbine 1/HRSG	5.49	44.20	353.6	435.2	18.41	n/a	0.176	n/a	1.579
Turbine 2/HRSG	5.49	44.20	353.6	435.2	18.41	n/a	0.176	n/a	1.579
Turbine 3/HRSG	5.49	44.20	353.6	435.2	18.41	n/a	0.176	n/a	1.579
Turbine 4/HRSG	5.49	44.20	353.6	435.2	18.41	n/a	0.176	n/a	1.579
Averaging Period: Annual SO2 and NOx									
Turbine 1/HRSG	5.49	44.20	353.6	435.2	18.41	2.103	0.166	n/a	n/a
Turbine 2/HRSG	5.49	44.20	353.6	435.2	18.41	2.103	0.166	n/a	n/a
Turbine 3/HRSG	5.49	44.20	353.6	435.2	18.41	2.103	0.166	n/a	n/a
Turbine 4/HRSG	5.49	44.20	353.6	435.2	18.41	2.103	0.166	n/a	n/a
Averaging Period: Annual PM10									
Turbine 1/HRSG	5.49	44.20	344.1	286.7	12.13	n/a	n/a	n/a	1.461
Turbine 2/HRSG	5.49	44.20	344.1	286.7	12.13	n/a	n/a	n/a	1.461
Turbine 3/HRSG	5.49	44.20	344.1	286.7	12.13	n/a	n/a	n/a	1.461
Turbine 4/HRSG	5.49	44.20	344.1	286.7	12.13	n/a	n/a	n/a	1.461

Table 6.2-2.5
Calculation of Fumigation Impacts

Emission Rates (g/s)

	NOx	SO2	CO (1-hr)	CO (8-hr)	PM10
Turbines (each)	2.363	0.183	3.454	40.36	1.579

SCREEN3 Modeling Results for Inversion Breakup Fumigation

	Unit Impacts (ug/m3 per g/s)	Modeled Impacts, ug/m3						
		NOx	SO2			CO		PM10
		1-hr avg	1-hr avg	3-hr avg	24-hr avg	1-hr avg	8-hr avg	24-hr avg
Turbines (each)	1.410	3.332	0.258	0.232	0.103	4.870	39.83	0.891
Total (four units)		13.33	1.03	0.93	0.41	19.48	159.32	3.56

SCREEN3 Modeling Results for Shoreline Fumigation

	Unit Impacts (ug/m3 per g/s)	One-Hour Impact (ug/m3)				
		NOx	SO2	CO 1-hr	CO 8-hr	PM10
Turbines (each)						
TIBL Factor = 2	0.991	2.342	0.181	3.423	39.992	1.565
TIBL Factor = 3	2.864	6.768	0.524	9.892	115.577	4.522
TIBL Factor = 4	5.569	13.160	1.019	19.235	224.737	8.793
TIBL Factor = 5	8.575	20.263	1.569	29.618	346.044	13.540
TIBL Factor = 6	11.120	26.277	2.035	38.408	448.748	17.558

SCREEN3 Results: Unit Impacts, Per Turbine

	Unit Impacts (ug/m3 per g/s)	NOx	SO2	CO 1-hr	CO 8-hr	PM10
One-Hour Impact (ug/m3)	1.221	2.89	0.22	4.22	49.27	1.93

Calculation of Shoreline Fumigation Impacts

	NOx	SO2			CO		PM10
	1-hr	1-hr	3-hr	24-hr	1-hr	8-hr	24-hr
TIBL Factor = 6	105.11	8.14	4.07	0.539	153.6	347.7	4.65

NOTES TO TABLE 6.2-2.5
FUMIGATION IMPACTS ANALYSIS

INVERSION BREAKUP FUMIGATION

Inversion breakup fumigation is generally a short-term phenomenon but was evaluated here as persisting for up to 24 hours. SCREEN3 was used to model one-hour unit impacts from the turbines and boilers under 2.5 m/s winds and F stability. .

One-hour impacts were adjusted for longer averaging periods using the EPA-recommended persistence factors for the SCREEN3 model, as follows:

- 3-hour average = 0.9 times 1-hour average
- 8-hour average = 0.7 times 1-hour average
- 24-hour average = 0.4 times 1-hour average

SHORELINE FUMIGATION

Shoreline fumigation was modeled for the turbines using SCREEN3 TIBL factors ranging from 2 to 6. The turbines were found to have highest impacts with a TIBL factor of 6. In accordance with EPA guidance, shoreline fumigation conditions were assumed to persist for up to 90 minutes.

For longer-term averaging periods, impacts were calculated using the highest modeled impact from SCREEN3 for the corresponding averaging period. A sample calculation for 24-hour average PM_{10} is as follows:

- For a single turbine, TIBL factor = 6; 1-hour average PM_{10} = 17.558 $\mu g/m^3$
- For a single turbine, maximum 1-hour average PM_{10} (from SCREEN3)= 1.93 $\mu g/m^3$
- Total impacts during the 24-hour period are calculated as 1.5 hours of shoreline fumigation, four turbines, plus 22.5 hours of operation under typical conditions (from SCREEN3): [(1.5 hrs * 17.558 $\mu g/m^3$) + (22.5 hrs * 1.93 $\mu g/m^3$)] ÷ 24 hrs * 4 turbines * 0.4 [persistence factor for converting 1-hour average screening impact into 24-hour average concentration] = 4.65 $\mu g/m^3$.

Table 6.2-2.6
Calculation of Modeled Impacts During Turbine Startup

Modeled unit impacts under 50% load conditions for the one- and three-hour averaging periods are:

one-hour average	108.69 ug/m3 per 4.0 gram per second
three-hour average	75.88 ug/m3 per 4.0 gram per second

Modeled unit impacts under base load conditions for the one- and three-hour averaging periods are:

one-hour average	90.75 ug/m3 per 4.0 gram per second
three-hour average	63.94 ug/m3 per 4.0 gram per second

Emission rates for modeling startup impacts (from Table 6.2-27) are:

Averaging Period	Pollutant	Startup Emission Rate, g/s	Base Load Emission Rate, g/s
1 hour	NOx	15.12	1.88
	SO2	0.097	0.15
	CO	156.24	2.75
3 hour	SO2	0.097	0.15

Total impacts are calculated by multiplying the unit impact in ug/m3 per g/s times the emission rate in grams per second.

Averaging Period	Pollutant	Modeled Impact, ug/m3
1 hour	NOx (1)	906.9
	NO2 (2)	185.9
	SO2	11.9
	CO	8615.4
3 hour	SO2	8.3

Notes:
(1) Without ozone limiting.
(2) With ozone limiting.

APPENDIX 6.2-3

SCREENING HEALTH RISK ASSESSMENT

APPENDIX 6.2-3
SCREENING HEALTH RISK ASSESSMENT

The health risk assessment was conducted in accordance with the procedures developed by the California Air Pollution Control Officers' Association (CAPCOA) in the Air Toxics "Hot Spots" Program: Revised 1992 Risk Assessment Guidelines, CAPCOA, (1993). The screening risk assessment evaluated two scenarios: the current operation of the boilers with support equipment (Diesel fire pumps, Diesel emergency generator, gasoline storage and dispensing, and boiler chemical charging) and the future operation of the turbines with support equipment (same as current operation without the boiler chemical charging).

The screening health risk assessment was carried out in three steps. First, emissions of noncriteria pollutants were calculated for sources at MBPP. These calculations are described in Section 6.2.5.1.1 and Appendix 6.2-1, Tables 6.2-1.7 through 1.9, and the emissions from the boilers and turbines are summarized in Tables 6.2-32 and 6.2-33.

Next, the ISCST3 model was used with unit emission rates for each source to calculate the contribution of each source to total concentration at each receptor. This was done using both the coarse grid of receptors and the sensitive receptors identified in Section 6.16. Impacts on Morro Rock are not included in this analysis. While the Rock is treated as ambient air for purposes of the ambient air quality standards, public access to the Rock is legally prohibited. Because the purpose of a screening health risk assessment is to evaluate potential public exposure, it is not appropriate to evaluate public health impacts in a location where the public is not permitted. A list of the discrete receptors is included in Table 6.16-1. Locations of the discrete receptors within 3 miles of the facility are shown in Figure 6.16-1. Maximum impacts of each compound for each source were calculated using the emission rates in Tables 6.2-1.7 through 1.9 and the modeled unit impacts; the results of these calculations are shown in Tables 6.2-3.1 through 3.3. Stack parameters for the auxiliary equipment included in the HRA are shown in Table 6.2-3.4.
Finally, the most current available OEHHA acute and chronic reference exposure levels and cancer unit risk values were used to evaluate acute, chronic and carcinogenic risks through inhalation pathways. The cancer risks for individual compounds were adjusted to account for multipathway exposure using multipathway adjustment factors developed by the SCAQMD.[1]

In accordance with draft ARB guidance on risk assessments for Diesel-fueled engines, Diesel exhaust particulate matter has been used as a surrogate for all toxic air contaminant emissions from Diesel-fueled engines in determining cancer risk and noncancer hazard index for these sources.

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[1] While the SCAQMD document provides a multipathway adjustment factor for chronic naphthalene exposure, the current OEHHA RELs indicate that naphthalene targets only the respiratory system. Therefore no chronic noninhalation effects are expected.

The locations of the three highest acute, carcinogenic and chronic exposures for the turbines and boilers are shown in Figure 6.2-3.1. As this figure shows, the locations of the maximum modeled acute, chronic and carcinogenic impacts are different for the gaseous pollutants, emitted principally by the turbines and boilers, and for the particulate matter emitted by the small, Diesel-fired emergency engines. Although these impacts occur in different places, the risks are combined to conservatively overestimate toxic risks from the facility. The modeling results show that the maximum modeled carcinogenic risk from the existing facility is 1.4 in one million, while the maximum modeled carcinogenic risk from the project is expected to be 2.4 in one million. This risk is well below the 10 in one million level considered significant. It is also important to note that 1.3 in one million of both risk levels is due to the occasional operation of the Diesel-fueled emergency equipment. The carcinogenic risks from the boilers and turbines alone are 0.1 and 1.1 in one million, respectively.

The chronic and acute noncarcinogenic hazard indices for the existing facility are 0.002 and 0.06, respectively. The chronic and acute noncarcinogenic hazard indices for the project are 0.009 and 0.04, respectively. Both are well below the significant impact level of 1. The modeling results are being submitted electronically.

Table 6.2-3.1
Maximum Modeled Impacts for Toxic Air Contaminants
Existing Facility

Compound	Modeled Impacts (ug/m3)							
	1994		1995		1996		Maximum	
	One-Hour Impacts	Annual Avg Impacts	One-Hour Impacts	Annual Avg Impacts	One-Hour Impacts	Annual Avg Impacts	One-Hour Impacts	Annual Avg Impacts
Ammonia	93.33	2.812E-01	46.85	2.886E-01	155.60	2.897E-01	155.60	2.897E-01
Arsenic	7.998E-02	9.155E-07	6.333E-02	8.900E-07	7.621E-02	8.812E-07	7.998E-02	9.155E-07
Benzene	6.762	7.715E-05	5.384	7.506E-05	6.636	7.431E-05	6.762	7.715E-05
Beryllium	3.342E-02	3.813E-07	2.661E-02	3.710E-07	3.280E-02	3.673E-07	3.342E-02	3.813E-07
Cadmium	2.003E-01	2.286E-06	1.595E-01	2.224E-06	1.966E-01	2.202E-06	2.003E-01	2.286E-06
Chromium VI	2.732E-04	3.117E-09	2.175E-04	3.033E-09	2.681E-04	3.002E-09	2.732E-04	3.117E-09
Copper	2.003E-01	2.286E-06	1.595E-01	2.224E-06	1.966E-01	2.202E-06	2.003E-01	2.286E-06
Diesel exhaust	n/a	4.477E-03	n/a	4.356E-03	n/a	4.312E-03	n/a	4.477E-03
Formaldehyde	5.090E-01	1.232E-04	4.052E-01	1.439E-04	4.995E-01	1.317E-04	5.090E-01	1.439E-04
Gasoline Vapors	2.709E+03	3.823E-02	2.872E+03	5.442E-02	4.682E+03	4.456E-02	4.682E+03	5.442E-02
Lead	6.684E-02	7.627E-07	5.322E-02	7.420E-07	6.560E-02	7.346E-07	6.684E-02	7.627E-07
Manganese	6.684E-02	7.627E-07	5.322E-02	7.420E-07	6.560E-02	7.346E-07	6.684E-02	7.627E-07
Mercury	2.003E-03	2.286E-08	1.595E-03	2.224E-08	1.966E-03	2.202E-08	2.003E-03	2.286E-08
Nickel	2.003E-01	2.286E-06	1.595E-01	2.224E-06	1.966E-01	2.202E-06	2.003E-01	2.286E-06
PAHs (1)	2.787E-02	3.180E-07	2.219E-02	3.094E-07	2.735E-02	3.062E-07	2.787E-02	3.180E-07
Phosphorus	2.003	2.286E-05	1.595	2.224E-05	1.966	2.202E-05	2.003	2.286E-05
Selenium	2.511E-02	1.775E-07	2.001E-02	1.946E-07	2.728E-02	1.812E-07	2.728E-02	1.946E-07
Zinc	2.003E-01	2.286E-06	1.595E-01	2.224E-06	1.966E-01	2.202E-06	2.003E-01	2.286E-06

(1) Polycyclic aromatic hydrocarbons.

Table 6.2-3.2
Maximum Modeled Impacts for Toxic Air Contaminants
Gas Turbines and Support Equipment

Compound	Modeled Impacts (ug/m3)							
	1994		1995		1996		Maximum	
	One-Hour Impacts	Annual Avg Impacts	One-Hour Impacts	Annual Avg Impacts	One-Hour Impacts	Annual Avg Impacts	One-Hour Impacts	Annual Avg Impacts
Acetaldehyde	0.638	5.630E-03	0.6542	6.839E-03	6.37E-01	5.90E-03	0.654	6.839E-03
Acrolein	5.984E-02	5.277E-04	6.047E-02	6.410E-04	5.974E-02	5.53E-04	6.047E-02	6.410E-04
Ammonia	63.57	0.603	64.24	7.33E-01	63.46	0.632	64.24	0.733
Arsenic	7.998E-02	9.155E-07	6.333E-02	8.900E-07	7.621E-02	8.81E-07	7.998E-02	9.155E-07
Benzene	6.762	1.118E-03	5.384	1.358E-03	6.637	1.17E-03	6.762	1.358E-03
Beryllium	3.342E-02	3.813E-07	2.661E-02	3.710E-07	3.280E-02	3.673E-07	3.342E-02	3.813E-07
1,3-Butadiene	1.182E-03	1.042E-05	1.194E-03	1.266E-05	1.180E-03	1.092E-05	1.194E-03	1.266E-05
Cadmium	2.003E-01	2.286E-06	1.595E-01	2.224E-06	1.966E-01	2.202E-06	2.003E-01	2.286E-06
Chromium VI	2.732E-04	3.117E-09	2.175E-04	3.033E-09	2.681E-04	3.002E-09	2.732E-04	3.117E-09
Copper	2.003E-01	2.286E-06	1.595E-01	2.224E-06	1.966E-01	2.202E-06	2.003E-01	2.286E-06
Diesel exhaust	n/a	4.477E-03	n/a	4.356E-03	n/a	4.312E-03	n/a	4.477E-03
Ethylbenzene	1.666E-01	1.469E-03	1.68E-01	1.784E-03	1.633E-01	1.539E-03	1.683E-01	1.784E-03
Formaldehyde	1.037	9.027E-03	1.047E+00	1.097E-02	1.039	9.459E-03	1.047	1.097E-02
Gasoline Vapors	2.709E+03	3.823E-02	2.872E+03	5.442E-02	4.682E+03	4.456E-02	4.682E+03	5.442E-02
Lead	6.684E-02	7.627E-07	5.322E-02	7.420E-07	6.560E-02	7.346E-07	6.684E-02	7.627E-07
Manganese	6.684E-02	7.627E-07	5.322E-02	7.420E-07	6.560E-02	7.346E-07	6.684E-02	7.627E-07
Mercury	2.003E-03	2.286E-08	1.595E-03	2.224E-08	1.966E-03	2.202E-08	2.003E-03	2.286E-08
Naphthalene	1.545E-02	1.362E-04	1.561E-02	1.655E-04	1.542E-02	1.427E-04	1.561E-02	1.655E-04
Nickel	2.003E-01	2.286E-06	1.595E-01	2.224E-06	1.966E-01	2.202E-06	2.003E-01	2.286E-06
PAHs (1)	6.346E-03	5.416E-05	6.404E-03	6.580E-05	7.826E-03	5.675E-05	7.826E-03	6.580E-05
Phosphorus	2.003	2.286E-05	1.595	2.224E-05	1.966	2.202E-05	2.003	2.286E-05
Propylene oxide	0.445	3.923E-03	4.50E-01	4.765E-03	4.44E-01	4.110E-03	0.450	4.765E-03
Selenium	2.511E-02	1.775E-07	2.001E-02	1.946E-07	2.728E-02	1.812E-07	2.728E-02	1.946E-07
Toluene	0.661	5.827E-03	6.68E-01	7.078E-03	0.660	6.106E-03	6.678E-01	7.078E-03
Xylene	2.429E-01	2.142E-03	2.455E-01	2.602E-03	0.243	2.244E-03	2.455E-01	2.602E-03
Zinc	2.003E-01	2.286E-06	1.595E-01	2.224E-06	1.966E-01	2.202E-06	2.003E-01	2.286E-06

(1) Polycyclic aromatic hydrocarbons.

Table 6.2-3.3
Maximum Modeled Impacts for Toxic Air Contaminants at Sensitive Receptors
Gas Turbines and Support Equipment

Compound	Modeled Impacts (ug/m3)							
	1994		1995		1996		Maximum	
	One-Hour Impacts	Annual Avg Impacts	One-Hour Impacts	Annual Avg Impacts	One-Hour Impacts	Annual Avg Impacts	One-Hour Impacts	Annual Avg Impacts
Acetaldehyde	0.069	1.899E-03	8.70E-02	1.950E-03	7.62E-02	1.60E-03	0.087	1.950E-03
Acrolein	6.498E-03	1.780E-04	8.150E-03	1.828E-04	7.138E-03	1.50E-04	8.150E-03	1.828E-04
Ammonia	6.90	0.204	8.66	0.209	7.58	0.171	8.66	0.209
Benzene	1.34	3.784E-04	1.17	3.886E-04	1.10	3.185E-04	1.34	3.886E-04
1,3-Butadiene	1.283E-04	3.516E-06	1.610E-04	3.610E-06	1.410E-04	2.955E-06	1.610E-04	3.610E-06
Diesel exhaust	n/a	1.167E-03	n/a	1.234E-03	n/a	1.193E-03	n/a	1.234E-03
Ethylbenzene	1.809E-02	4.956E-04	2.27E-02	5.088E-04	1.99E-02	4.165E-04	2.269E-02	5.088E-04
Formaldehyde	0.195	3.046E-03	0.203	3.127E-03	0.204	2.560E-03	0.204	3.127E-03
Gasoline Vapors	117.30	5.678E-03	44.61	5.888E-03	43.28	5.890E-03	117.30	5.890E-03
Naphthalene	1.677E-03	4.596E-05	2.104E-03	4.718E-05	1.843E-03	3.863E-05	2.104E-03	4.718E-05
PAHs (1)	2.127E-03	1.828E-05	2.053E-03	1.876E-05	2.000E-03	1.536E-05	2.127E-03	1.876E-05
Propylene oxide	4.830E-02	1.324E-03	6.06E-02	1.359E-03	5.31E-02	1.112E-03	6.059E-02	1.359E-03
Toluene	7.175E-02	1.966E-03	8.999E-02	2.018E-03	7.882E-02	1.652E-03	8.999E-02	2.018E-03
Xylene	2.637E-02	7.227E-04	3.308E-02	7.418E-04	2.897E-02	6.074E-04	3.308E-02	7.418E-04

(1) Polycyclic aromatic hydrocarbons.

Calculation of Acute Inhalation Hazard Index
MBPP Project
Existing Boilers, All Receptors

Pollutant Name	Max. Modeled 1-hr Conc, ug/m3	Acute REL, ug/m3 (1)	Toxicological Endpoints	Acute Inhalation Hazard Index
Ammonia	1.56E+02	3.20E+03	Eye and respiratory irritation	4.86E-02
Benzene	6.76E+00	1.30E+03	Reproductive/ developmental	5.20E-03
Formaldehyde	5.09E-01	9.40E+01	Eye irritation	5.41E-03
Total				5.92E-02

Calculation of Acute Inhalation Hazard Index
MBPP Project
New Turbines, All Receptors

Pollutant Name	Max. Modeled 1-hr Conc, ug/m3	Acute REL, ug/m3 (1)	Toxicological Endpoints	Acute Inhalation Hazard Index
Acrolein	6.047E-02	1.90E-01	Eye irritation	3.18E-01
Ammonia	64.24	3.20E+03	Eye and respiratory irritation	2.01E-02
Benzene	6.762	1.30E+03	Reproductive/ Developmental	5.20E-03
Formaldehyde	1.047	9.40E+01	Eye irritation	1.11E-02
Propylene oxide	0.450	3.10E+03	Eye and respiratory irritation	1.45E-04
Toluene	6.678E-01	3.70E+04	CNS-- mild; Eye and respiratory irritation	1.80E-05
Xylene	2.455E-01	2.20E+04	Eye and respiratory irritation	1.12E-05
Total				3.55E-01

Calculation of Chronic Inhalation Hazard Index
MBPP Project
Existing Boilers, All Receptors

Pollutant Name	Max. Modeled Annual Avg Conc. ug/m3	Chronic REL, ug/m3 (1)	Toxicological Endpoints	Chronic Inhalation Hazard Index
Ammonia	2.90E-01	2.00E+02	Respiratory irritation	1.45E-03
Benzene	7.72E-05	6.00E+01	Hematopoietic system; development; nervous system	1.29E-06
Diesel exhaust	4.48E-03	5.00E+00	Respiratory system	8.95E-04
Formaldehyde	1.44E-04	3.00E+00	Respiratory system; eyes	4.80E-05
Gasoline vapors	5.44E-02	2.10E+03		2.59E-05
Total				2.42E-03

Calculation of Chronic Inhalation Hazard Index
MBPP Project
New Turbines, All Receptors

Pollutant Name	Max. Modeled Annual Avg Conc. ug/m3	Chronic REL, ug/m3 (1)	Toxicological Endpoints	Chronic Inhalation Hazard Index
Ammonia	7.33E-01	2.00E+02	Respiratory irritation	3.67E-03
Acetaldehyde	6.84E-03	9.00E+00	Respiratory system	7.60E-04
Benzene	1.36E-03	6.00E+01	Hematopoietic system; development; nervous system	2.26E-05
Diesel exhaust	4.48E-03	5.00E+00	Respiratory system	8.95E-04
Ethylbenzene	1.78E-03	2.00E+03	Development; alimentary system (liver); kidney; endocrine system	8.92E-07
Formaldehyde	1.10E-02	3.00E+00	Respiratory system; eyes	3.66E-03
Gasoline vapors	5.44E-02	2.10E+03		2.59E-05
Naphthalene	1.66E-04	9.00E+00	Respiratory system	1.84E-05
Propylene oxide	4.77E-03	3.00E+01	Respiratory system	1.59E-04
Toluene	7.08E-03	3.00E+02	Nervous system; respiratory system; development	2.36E-05
Xylene	2.60E-03	7.00E+02	Nervous system; respiratory system	3.72E-06
Total				9.23E-03

Calculation of Cancer Risk
MBPP Project
Existing Boilers, All Receptors

Pollutant Name	Max. Modeled Annual Avg Conc. ug/m3	Unit Risk, (ug/m3)-1 in one million	Multipathway Adjustment Factor	Cancer Risk in one million
Benzene	7.72E-05	2.90E+01	1	2.24E-03
Diesel exhaust	4.48E-03	3.00E+02	n/a	1.34E+00
Formaldehyde	1.44E-04	6.00E+00	1	8.63E-04
Gasoline vapors	5.44E-02	1.60E+00	1	8.71E-02
Total				1.43E+00

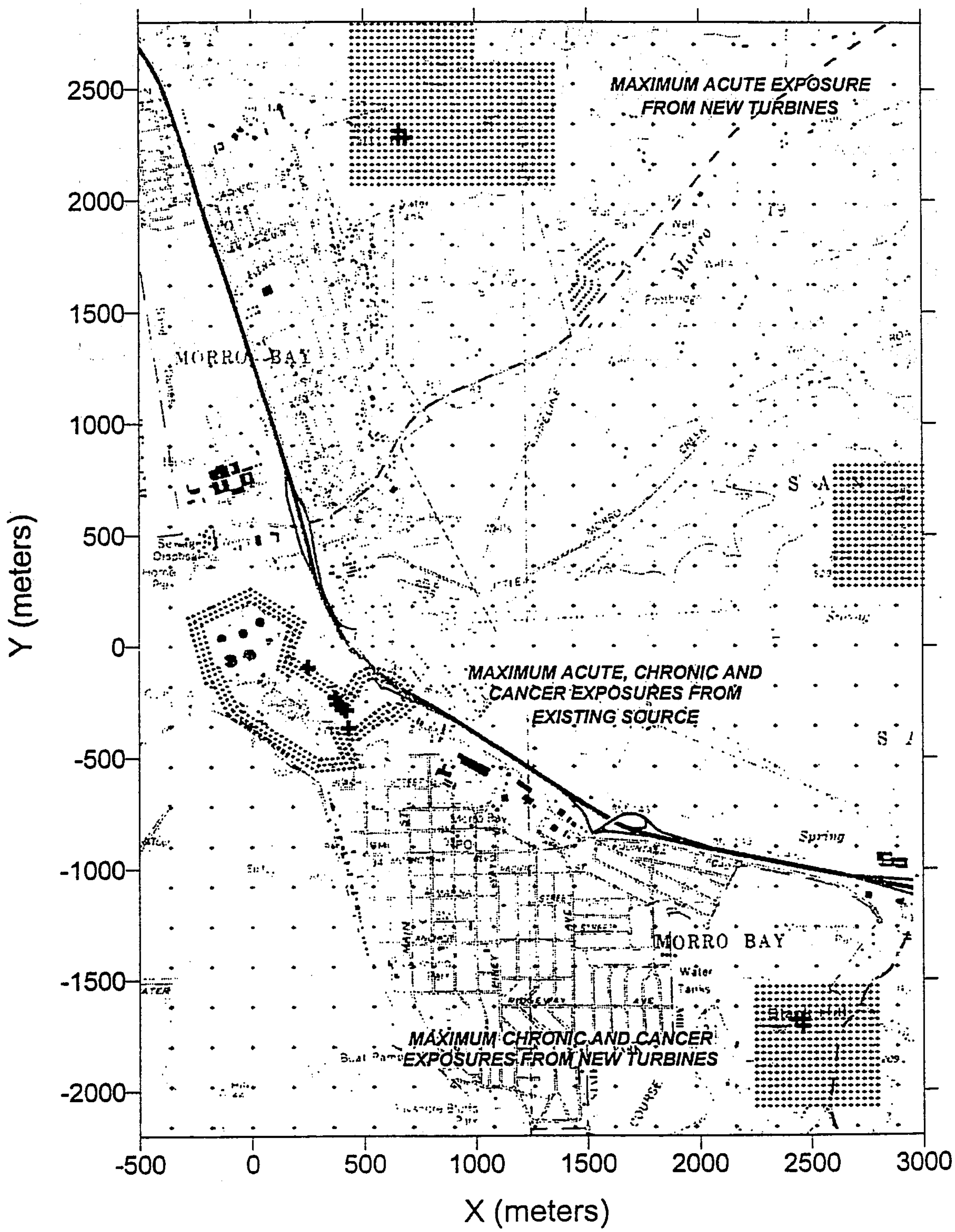
Calculation of Cancer Risk
MBPP Project
New Turbines, All Receptors

Pollutant Name	Max. Modeled Annual Avg Conc. ug/m3	Unit Risk, (ug/m3)-1 in one million	Multipathway Adjustment Factor	Cancer Risk in one million
Acetaldehyde	6.84E-03	2.70E+00	1	1.85E-02
Benzene	1.36E-03	2.90E+01	1	3.94E-02
1,3-Butadiene	1.27E-05	1.70E+02	1	2.15E-03
Diesel exhaust	4.48E-03	3.00E+02	n/a	1.34E+00
Formaldehyde	1.10E-02	6.00E+00	1	6.58E-02
Gasoline vapors	5.44E-02	1.60E+00	1	8.71E-02
PAHs (as benzo(a)pyrene)	6.58E-05	1.10E+03	12.7	9.19E-01
Propylene oxide	4.77E-03	3.70E+00	1	1.76E-02
Total				2.49E+00

Calculation of Cancer Risk
MBPP Project
New Turbines, Sensitive Receptors

Pollutant Name	Max. Modeled Annual Avg Conc. ug/m3	Unit Risk, (ug/m3)-1 in one million	Multipathway Adjustment Factor	Cancer Risk in one million
Acetaldehyde	1.95E-03	2.70E+00	1	5.27E-03
Benzene	3.89E-04	2.90E+01	1	1.13E-02
1,3-Butadiene	3.61E-06	1.70E+02	1	6.14E-04
Diesel exhaust	1.23E-03	3.00E+02	n/a	3.70E-01
Formaldehyde	3.13E-03	6.00E+00	1	1.88E-02
Gasoline vapors	5.89E-03	1.60E+00	1	9.42E-03
PAHs (as benzo(a)pyrene)	1.88E-05	1.10E+03	12.7	2.62E-01
Propylene oxide	1.36E-03	3.70E+00	1	5.03E-03
Total				6.83E-01

Figure 6.2-3.1
Locations of Modeled Maximum
Acute Chronic and Cancer Risks from
Existing Sources and NewTurbines
at Morro Bay Power Plant



APPENDIX 6.2-4

DEMONSTRATION OF COMPLIANCE WITH DISTRICT RULE 219

APPENDIX 6.2-4
DEMONSTRATION OF COMPLIANCE WITH DISTRICT RULE 219

For the demonstration of compliance with SLOCAPCD Rule 219, Toxics New Source Review, only the new gas turbines are evaluated as they are the only new sources at the facility. The three-step evaluation procedure was identical to that outlined in Appendix 6.2-3 for the screening health risk assessment, with the exception that only the turbines were included.

The calculation of toxic emissions from the turbines is shown in Appendix 6.2, Table 6.2-1.9, and the results are summarized in Table 6.2-26. The three nearest residential areas (the mobile home park to the north, the Morro Rock Park Tract to the southeast and the Harbor Front Tract to the east) were included in the modeling of residential impacts. The residences in the mobile home park are nearest the plant (less than 1000 feet away), but are upwind of the plant most of the time. The Morro Rock Park and Harbor Front Tracts are approximately 2000 feet from the plant but are the nearest downwind residential areas. Maximum modeled one-hour and annual average concentrations at residential receptors are shown in Table 6.2-4.1.

The calculated acute and chronic hazard indices and cancer risk for the turbines are included in this appendix. Separate calculations are shown for each type of exposure and risk and the results of the calculations are also included here. This risk assessment shows that the carcinogenic risk and chronic noncarcinogenic hazard indices are below the Rule 219 limit of 1.0 in one million and 0.1, respectively. The results also show that when the CATEF data base emission factors are used, the acute hazard index is 0.08, which is below the Rule 219 limit of 0.1. Examination of the contributions to acute hazard shows that 91% of the acute hazard is due to acrolein. Source test results recently submitted to the CEC in the Metcalf Energy Center proceeding (summary included here) showed that acrolein was not detected in the turbine exhaust at either full or part loads. In accordance with ARB's AB2588 guidance (see references), when a substance is not detected in any of the tests, the substance can be assumed not to be present. If the acute hazard index is adjusted to eliminate the expected zero contribution from acrolein, the index is 0.008, which is well below the Rule 219 limit of 0.1.

Table 6.2-4.1
Maximum Modeled Impacts for Toxic Air Contaminants
Gas Turbines Only (Residential Receptors)

Compound	Modeled Impacts (ug/m3)							
	1994		1995		1996		Maximum	
	One-Hour Impacts	Annual Avg Impacts	One-Hour Impacts	Annual Avg Impacts	One-Hour Impacts	Annual Avg Impacts	One-Hour Impacts	Annual Avg Impacts
Acetaldehyde	0.161	8.060E-04	0.153	8.604E-04	0.166	7.450E-04	0.166	8.604E-04
Acrolein	1.511E-02	7.555E-05	1.429E-02	8.064E-05	1.510E-02	6.983E-05	1.511E-02	8.064E-05
Ammonia	16.06	0.086	15.18	9.22E-02	16.04	7.986E-02	16.06	9.222E-02
Arsenic	0	0	0	0	0	0	0	0
Benzene	3.20E-02	1.598E-04	3.02E-02	1.706E-04	3.19E-02	1.477E-04	0.032	1.706E-04
Beryllium	0	0	0	0	0	0	0	0
1,3-Butadiene	2.985E-04	1.492E-06	2.220E-04	1.593E-06	2.983E-04	1.379E-06	2.985E-04	1.593E-06
Cadmium	0	0	0	0	0	0	0	0
Chromium VI	0	0	0	0	0	0	0	0
Copper	0	0	0	0	0	0	0	0
Diesel exhaust	n/a	0	n/a	0	n/a	0	n/a	0
Ethylbenzene	4.208E-02	2.103E-04	3.98E-02	2.245E-04	4.204E-02	1.944E-04	4.208E-02	2.245E-04
Formaldehyde	0.259	1.292E-03	0.245	1.380E-03	0.258	1.195E-03	0.259	1.380E-03
Gasoline Vapors	0	0	0	0	0	0	0	0
Lead	0	0	0	0	0	0	0	0
Manganese	0	0	0	0	0	0	0	0
Mercury	0	0	0	0	0	0	0	0
Naphthalene	3.902E-03	1.950E-05	3.689E-03	2.082E-05	3.899E-03	1.803E-05	3.902E-03	2.082E-05
Nickel	0	0	0	0	0	0	0	0
PAHs (1)	1.552E-03	7.857E-06	1.467E-03	8.278E-06	1.550E-03	7.169E-06	1.552E-03	8.278E-06
Phosphorus	0	0	0	0	0	0	0	0
Propylene oxide	0.112	5.616E-04	0.106	5.995E-04	0.112	5.191E-04	0.112	5.995E-04
Selenium	0	0	0	0	0	0	0	0
Toluene	0.167	8.342E-04	0.158	8.905E-04	0.167	7.711E-04	0.167	8.905E-04
Xylene	6.135E-02	3.067E-04	5.800E-02	3.273E-04	6.130E-02	2.835E-04	0.061	3.273E-04
Zinc	0	0	0	0	0	0	0	0

(1) Polycyclic aromatic hydrocarbons.

Calculation of Acute Inhalation Hazard Index
MBPP Project
New Turbines, Residential Receptors

Pollutant Name	Max. Modeled 1-hr Conc, ug/m3	Acute REL, ug/m3 (1)	Toxicological Endpoints	Acute Inhalation Hazard Index
Acrolein	1.511E-02	1.90E-01	Eye irritation	7.95E-02
Ammonia	16.06	3.20E+03	Eye and respiratory irritation	5.02E-03
Benzene	3.197E-02	1.30E+03	Reproductive/ Developmental	2.46E-05
Formaldehyde	0.259	9.40E+01	Eye irritation	2.75E-03
Propylene oxide	0.112	3.10E+03	Eye and respiratory irritation	3.63E-05
Toluene	1.669E-01	3.70E+04	CNS-- mild; Eye and respiratory irritation	4.51E-06
Xylene	6.135E-02	2.20E+04	Eye and respiratory irritation	2.79E-06
Total				8.74E-02

Calculation of Chronic Inhalation Hazard Index
MBPP Project
New Turbines, Residential Receptors

Pollutant Name	Max. Modeled Annual Avg Conc, ug/m3	Chronic REL, ug/m3 (1)	Toxicological Endpoints	Chronic Inhalation Hazard Index
Ammonia	9.22E-02	2.00E+02	Respiratory irritation	4.61E-04
Acetaldehyde	8.60E-04	9.00E+00	Respiratory system	9.56E-05
Benzene	1.71E-04	6.00E+01	Hematopoietic system; development; nervous system	2.84E-06
Ethylbenzene	2.25E-04	2.00E+03	Development; alimentary system (liver); kidney; endocrine system	1.12E-07
Formaldehyde	1.38E-03	3.00E+00	Respiratory system; eyes	4.60E-04
Naphthalene	2.08E-05	9.00E+00	Respiratory system	2.31E-06
Propylene oxide	6.00E-04	3.00E+01	Respiratory system	2.00E-05
Toluene	8.91E-04	3.00E+02	Nervous system; respiratory system; development	2.97E-06
Xylene	3.27E-04	7.00E+02	Nervous system; respiratory system	4.68E-07
Total				1.05E-03

Calculation of Cancer Risk
MBPP Project
New Turbines, Residential Receptors

Pollutant Name	Max. Modeled Annual Avg Conc, ug/m3	Unit Risk, (ug/m3)-1 in one million	Multipathway Adjustment Factor	Cancer Risk in one million
Acetaldehyde	8.60E-04	2.70E+00	1	2.32E-03
Benzene	1.71E-04	2.90E+01	1	4.95E-03
1,3-Butadiene	1.59E-06	1.70E+02	1	2.71E-04
Formaldehyde	1.38E-03	6.00E+00	1	8.28E-03
PAHs (as benzo(a)pyrene)	8.28E-06	1.10E+03	12.7	1.16E-01
Propylene oxide	6.00E-04	3.70E+00	1	2.22E-03
Total				1.34E-01

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August 3, 2000

Dennis Jang
Air Quality Engineer
Permit Services Division
Bay Area Air Quality Management District
939 Ellis Street
San Francisco, CA 94109

RE: Metcalf Energy Center
Application No. 27215

Dear Mr. Jang:

Because of the questions that have been raised by many interested parties regarding the emissions of formaldehyde, acetaldehyde, and acrolein from the large gas turbines equipped with dry, low-NOx combustors that will be used at Calpine/Bechtel's Metcalf Energy Center, source testing was performed on June 15, 2000, at Calpine's Pasadena, Texas facility. As discussed in our July 7 letter regarding earlier source testing at the Pasadena facility, the Pasadena I gas turbine is a slightly older generation of the Westinghouse 501F proposed for use at MEC. The turbine is equipped with a selective catalytic reduction system for NOx control, but does not use an oxidation catalyst. Power augmentation steam injection was in use during the tests; the Pasadena I facility is not equipped with a duct burner.

These test results are notable for several reasons. First, in accordance with ARB's recent guidance, acrolein was not measured using CARB Method 430. To determine acrolein concentrations, three stack gas samples were drawn into six-liter Summa canisters (to prevent sample deterioration) and the samples were analyzed using EPA Method TO-14.

Second, all of the acetaldehyde and acrolein samples, as well as one of the three formaldehyde samples, were below the levels of detection for the test methods. Thus, these test results provide a conservative upper bound assessment of emissions of these compounds.

Finally, because of limitations in EPA Method TO-14 related to moisture and CO_2 concentrations in the samples, two of the three acrolein samples had to be diluted by a factor of somewhat greater than six to permit analysis without damaging the instrumentation. Unfortunately, this had the effect of increasing the detection limit for two of the three tests from 2 ppb to 13 to 14 ppb. As this result is not related in any way to the concentration of acrolein in the exhaust gas, we believe that the results of Run 1 best represent the actual measured concentration (which again is below the detection limit).

The test results are summarized in the following tables. The test report presents the test results in units of ppm and pounds per hour. Operating data collected at the time of the testing (copy attached) were used to calculate emission factors in units of pounds per million Btu of fuel burned. The tables compare the emission factors calculated from the test results with the CATEF emission factors that were used in the AFC as well as the factors from the latest update to AP-42.

Acetaldehye Emissions						
Run	Emissions, ppm	Emissions, lb/hr	Measured Fuel Flow, MMscf/hr	Calculated Emission Factor, lb/MMscf	CATEF Emission Factor, lb/MMscf	AP-42 Emission Factor, lb/MMscf*
1	<0.02	<0.125	1.642	<0.0761		
2	<0.03	<0.129	1.619	<0.0797		
3	<0.02	<0.106	1.619	<0.0655		
Average	<0.02	<0.120	1.627	<7.38E-02	6.86E-02	4.09E-02

Formaldehyde Emissions						
Run	Emissions, ppm	Emissions, lb/hr	Measured Fuel Flow, MMscf/hr	Calculated Emission Factor, lb/MMscf	CATEF Emission Factor, lb/MMscf	AP-42 Emission Factor, lb/MMscf*
1	0.08	0.288	1.642	0.175		
2	0.09	0.292	1.619	0.180		
3	<0.06	<0.223	1.619	<0.138		
Average	<0.08	<0.268	1.627	<0.165	0.23	0.726

Acrolein Emissions						
Run	Emissions, ppm	Emissions, lb/hr	Measured Fuel Flow, MMscf/hr	Calculated Emission Factor, lb/MMscf	CATEF Emission Factor, lb/MMscf	AP-42 Emission Factor, lb/MMscf*
1	<0.003	<0.019	1.642	<1.16E-02**	6.43E-03	6.54E-03
2	<0.014	<0.089	1.619	<0.0550***		
3	<0.013	<0.084	1.619	<0.0519***		

Notes * AP-42 Table 3.1-3: Emission factors for Hazardous Air Pollutants from Natural Gas-Fired Stationary Gas Turbines, 4/00. Converted from lb/MMBtu per footnote c.

** Note that the AP-42 emission factor tables in Section 3.1 indicate that when the compound is not detected, the presented emission factor is based on one-half of the detection limit. Following this practice, the test result for acrolein would be 5.80E-03.

*** Test result not used because of excessive sample dilution.

We believe that these test results demonstrate that the formaldehyde, acetaldehyde, and acrolein emission factors that we used in the MEC AFC Supplement C analysis of toxic emissions are appropriate.

Copies of the test report and process data are enclosed for your information. If you have any questions or require additional information about this or any other aspect of the project, please do not hesitate to call.

Sincerely,

Gary Rubenstein

enclosures

cc: (with enclosures)
Mike Ringer, CEC
Paul Richins, CEC
Mike Tollstrup, California Air Resources Board
Ray Menebroker, California Air Resources Board
Gerardo Rios, EPA Region IX
Duong Nguyen, EPA Region IX
Matt Haber, EPA Region IX
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August 21, 2000

Dennis Jang
Air Quality Engineer
Permit Services Division
Bay Area Air Quality Management District
939 Ellis Street
San Francisco, CA 94109

RE: Metcalf Energy Center
Application No. 27215

Dear Mr. Jang:

In response to questions raised by interested parties regarding emissions of formaldehyde, acetaldehyde, and acrolein at low loads from the large gas turbines equipped with dry, low-NOx combustors, source testing was performed on July 20 and 21, 2000, at Calpine's Pasadena, Texas facility.

As discussed in earlier letters on this subject, the Siemens-Westinghouse (S-W) 501FC gas turbine source tested at Pasadena is an older model of the S-W 501F. The S-W 501FD2 machine to be operated at MEC includes a modified, higher temperature fourth stage blade. The compressor and combustion system have not been modified, thus providing the expectation that turbine emissions should be almost identical. The turbine is equipped with a selective catalytic reduction system for NOx control and does not use an oxidation catalyst. The Pasadena I facility is not equipped with a duct burner.

As in the full-load testing carried out in June 2000 on this gas turbine, in accordance with ARB's recent guidance, acrolein was not measured using CARB Method 430. To determine acrolein concentrations, three stack gas samples were drawn into 6-liter Summa canisters (to prevent sample deterioration) and the samples were analyzed using EPA Method TO-14.

As with the full-load tests, all of the acetaldehyde samples, as well as two of the three acrolein samples, were below the levels of detection for the test methods. Thus, these test results provide a conservative upper-bound assessment of emissions of these compounds.

We note that there is a huge discrepancy between the first two acrolein samples, in which the concentrations were below the limits of detection, and the third sample, taken on a different day. The third sample shows what we believe to be an erroneously high acrolein concentration that is completely inconsistent with the formaldehyde and acetaldehyde concentrations obtained at the same time. If in fact the acrolein emissions from the turbine were high because of some combustion phenomenon that was causing acrolein formation, one would expect to see the same trend in formaldehyde and acetaldehyde concentrations as all three compounds are the products of incomplete combustion. In fact, no such trend is observed. We believe that the lack of a corresponding increase in formaldehyde emissions during the third run indicates that combustion is not the source of the elevated acrolein levels.

The analytical laboratory, Air Toxics Ltd., has reviewed canister records and all test results and determined that the reported results are valid for all tests, ruling out sample or canister contamination at the laboratory. We are scheduling another triplicate test to verify that the first two runs accurately characterize acrolein emissions from the gas turbine at part load.

The test results are summarized in the following tables. The test report presents the test results in units of ppm and pounds per hour. Operating data collected at the time of the testing (copy attached) were used to calculate emission factors in units of pounds per million standard cubic feet (MMscf) of fuel burned. The tables compare the emission factors calculated from the test results with the CATEF emission factors that were used in the AFC, as well as the factors from the latest update to AP-42.

Acetaldehyde Emissions: Part-Load

Run	Emissions, ppm	Emissions, lb/hr	Measured Fuel Flow, MMscf/hr	Calculated Emission Factor, lb/MMscf	CATEF Emission Factor, lb/MMscf	AP-42 Emission Factor, lb/MMscf*
1	<0.01	<0.063	1.195	<0.0527		
2	<0.01	<0.056	1.196	<0.0468		
3	<0.02	<0.082	1.203	<0.0682		
Average	<0.01	<0.067	1.198	<5.59E-02	6.86E-02	4.09E-02

Formaldehyde Emissions: Part-Load

Run	Emissions, ppm	Emissions, lb/hr	Measured Fuel Flow, MMscf/hr	Calculated Emission Factor, lb/MMscf	CATEF Emission Factor, lb/MMscf	AP-42 Emission Factor, lb/MMscf*
1	0.10	0.307	1.195	0.257		
2	0.10	0.319	1.196	0.267		
3	0.13	0.419	1.203	0.348		
Average	0.11	0.348	1.198	0.291	0.11	0.726

Acrolein Emissions: Part-Load

Run	Emissions, ppm	Emissions, lb/hr	Measured Fuel Flow, MMscf/hr	Calculated Emission Factor, lb/MMscf	CATEF Emission Factor, lb/MMscf	AP-42 Emission Factor, lb/MMscf*
1	<0.002	<0.012	1.195	<1.00E-02**		
2	<0.002	<0.012	1.196	<1.00E-02**		
3	0.240	--	--	***		
Average	<0.002	<0.012	1.196	<0.010	6.43E-03	6.54E-03

Notes * AP-42 Table 3.1-3: Emission factors for Hazardous Air Pollutants from Natural Gas-Fired Stationary Gas Turbines, 4/00. Converted from lb/MMBtu per footnote c.

** Note that the AP-42 emission factor tables in Section 3.1 indicate that when the compound is not detected, the presented emission factor is based on one-half of the detection limit. Following this practice, the test result for acrolein would be 5.0E-03.

*** Test result not used because of suspected contamination.

We believe that these test results, in combination with the full-load results provided earlier this month, demonstrate that the formaldehyde, acetaldehyde, and acrolein emission factors used in the MEC AFC Supplement C analysis of toxic emissions are appropriate.

Copies of the test report and process data are enclosed for your information. If you have any questions or require additional information about this or any other aspect of the project, please do not hesitate to call.

Sincerely,

Gary Rubenstein

Gary Rubenstein

enclosures

cc: (with enclosures)
Mike Ringer, CEC
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APPENDIX 6.2-5
CONSTRUCTION AND DEMOLITION EMISSIONS AND IMPACT ANALYSIS

APPENDIX 6.2-5
CONSTRUCTION AND DEMOLITION EMISSIONS AND IMPACT ANALYSIS

6.2-5.1 CONSTRUCTION PHASES

Construction of the Project is expected to last approximately 20 months, with the construction occurring in the following four main phases:

- Tank demolition;
- Site preparation;
- Foundation work;
- Installation of major equipment; and
- Construction/installation of major structures.

Demolition of the existing fuel storage tanks is expected to take about three months. This will be followed by site preparation, which includes clearing, grading, excavation of footings and foundations, and backfilling operations. After site preparation is finished, the construction of the foundations and structures is expected to begin. Once the foundations and structures are finished, installation and assembly of the mechanical and electrical equipment are scheduled to commence.

Fugitive dust emissions from the construction of the Project will result from:

- Dust entrained during site preparation and grading/excavation at the construction site;
- Dust entrained during onsite travel on paved and unpaved surfaces;
- Dust entrained during aggregate and soil loading and unloading operations; and
- Wind erosion of areas disturbed during construction activities.

Combustion emissions during construction will result from:

- Exhaust from the Diesel construction equipment used for site preparation, grading, excavation, and construction of onsite structures;
- Exhaust from water trucks used to control construction dust emissions;
- Exhaust from Diesel-powered welding machines, electric generators, air compressors, and water pumps;
- Exhaust from pickup trucks and Diesel trucks used to transport workers and materials around the construction site;
- Exhaust from Diesel trucks used to deliver concrete, fuel, and construction supplies to the construction site;
- Exhaust from locomotives used to deliver mechanical equipment to the project area; and
- Exhaust from automobiles used by workers to commute to the construction site.

To determine the potential worst-case daily construction impacts, exhaust and dust emission rates have been evaluated for each source of emissions. Worst-case daily dust emissions are expected to occur during the early months of construction when site preparation occurs (i.e., month five of the construction schedule). The worst-case daily exhaust emissions are expected to occur in the middle of the construction schedule during the installation of the major mechanical equipment (i.e., month ten of the construction schedule). Annual emissions are based on the average equipment mix during the 20-month construction period.

6.2-5.2 DEMOLITION ACTIVITIES

As discussed in Section 2.3, workforce loadings and vehicle traffic during Stage II, the demolition phase, will be very low and will never reach levels encountered during the construction phase. Therefore, emissions from demolition activities will be lower than emissions from construction activities and they are not assessed further.

6.2-5.3 AVAILABLE MITIGATION MEASURES

The following mitigation measures are proposed to control exhaust emissions from the Diesel heavy equipment used during construction of the Project:

- Operational measures, such as limiting time spent with the engine idling by shutting down equipment when not in use;
- Regular preventive maintenance to prevent emission increases due to engine problems;
- Use of low sulfur and low aromatic fuel meeting California standards for motor vehicle Diesel fuel; and
- Use of low-emitting Diesel engines meeting federal emissions standards for construction equipment.

The following mitigation measures are proposed to control fugitive dust emissions during construction of the project:

- Use either water application or chemical dust suppressant application to control dust emissions from unpaved road travel and unpaved parking areas;
- Use vacuum sweeping and/or water flushing of paved road surface to remove buildup of loose material to control dust emissions from travel on the paved access road (including adjacent public streets impacted by construction activities) and paved parking areas;
- Cover all trucks hauling soil, sand, and other loose materials or require all trucks to maintain at least 2 feet of freeboard;
- Limit traffic speeds on unpaved roads to 15 mph;
- Install sandbags or other erosion control measures to prevent silt runoff to roadways;
- Replant vegetation in disturbed areas as quickly as possible;

- Use wheel washers or wash off tires of all trucks exiting construction site that carry track-out dirt from unpaved roads; and
- Mitigate fugitive dust emissions from wind erosion of areas disturbed from construction activities (including storage piles) by application of either water or chemical dust suppressant.

6.2-5.4 ESTIMATION OF EMISSIONS WITH MITIGATION MEASURES

Tables 6.2-5.1 through 6.2-5.3 show the estimated maximum daily and annual heavy equipment exhaust and fugitive dust emissions with recommended mitigation measures. Detailed emission calculations are included as Attachment 6.2-5.1.

TABLE 6.2-5.1
MAXIMUM DAILY EMISSIONS DURING CONSTRUCTION (MONTH 5; MAXIMUM DUST EMISSIONS), POUNDS PER DAY

	NOx	CO	VOC	SOx	PM_{10}
Onsite					
Construction Equipment, Fugitive Dust	119.6	258.8	22.0	4.0	33.3
Offsite					
Worker Travel, Truck/Rail Deliveries	39.8	174.0	15.7	1.5	2.0
Total Emissions					
Total =	159.4	432.8	37.6	5.4	35.3

TABLE 6.2-5.2
MAXIMUM DAILY EMISSIONS DURING CONSTRUCTION (MONTH 10; MAXIMUM EXHAUST EMISSIONS), POUNDS PER DAY

	NOx	CO	VOC	SOx	PM_{10}
Onsite					
Construction Equipment, Fugitive Dust	242.6	520.4	45.1	8.0	29.2
Offsite					
Worker Travel, Truck/Rail Deliveries	106.0	589.9	50.6	3.5	3.6
Total Emissions					
Total =	348.6	1,110.3	95.6	11.5	32.8

TABLE 6.2-5.3
ANNUAL EMISSIONS DURING CONSTRUCTION, TONS PER YEAR

	NOx	CO	VOC	SOx	PM_{10}
Onsite					
Construction Equipment, Fugitive Dust	28.1	47.9	4.5	0.9	5.1
Offsite					
Worker Travel, Truck/Rail Deliveries	9.3	99.5	8.2	0.1	0.2
Total Emissions					
Total =	37.4	147.5	12.7	0.9	5.3

6.2-5.5 ANALYSIS OF AMBIENT IMPACTS FROM FACILITY CONSTRUCTION

Ambient air quality impacts from emissions during construction of the Project were estimated using an air quality dispersion modeling analysis. The modeling analysis considers the construction site location, the surrounding topography, and the sources of emissions during construction, including vehicle and equipment exhaust emissions and fugitive dust.

6.2-5.5.1 EXISTING AMBIENT LEVELS

As with the modeling analysis of project operating impacts (Section 6.2.5.3), the Morro Bay, San Luis Obispo, and Grover City monitoring stations were used to establish the ambient background levels for the construction impact modeling analysis. Table 6.2-5.4 shows the maximum concentrations of NOx, SO_2, CO, and PM_{10} recorded for 1997 through 1999 at those monitoring stations.

6.2-5.5.2 DISPERSION MODEL

As in the analysis of project operating impacts, the EPA-approved Industrial Source Complex Short Term (ISCST3) model was used to estimate ambient impacts from construction activities. A detailed discussion of the ISCST3 dispersion model is included in Section 6.2.5.3.

The emission sources for the construction site were grouped into two categories: exhaust emissions and dust emissions. An effective emission plume height of 2.0 meters was used for all exhaust emissions. For construction dust emissions, an effective plume height of 0.5 meters was used in the modeling analysis. The exhaust and dust emissions were modeled as a single area source that covered the total area of the construction site. The construction impacts modeling analysis used the same receptor locations as used for the project operating impact analysis. A detailed discussion of the receptor locations is included in Section 6.2.5.3.

To determine the construction impacts on short-term ambient standards (24 hours and less), the worst-case daily onsite construction emission levels shown in Tables 6.2-5.1 and 6.2-5.2 were used. For pollutants with annual average ambient standards, the annual onsite emission levels shown in Table 6.2-5.3 were used. As with the project operating impact analysis, the meteorological data set used for the construction emission impacts analysis is data collected by PG&E at MBPP between 1994 and 1996.

6.2-5.5.3 MODELING RESULTS

Based on the emission rates of NOx, SO_2, CO, and PM_{10} and the meteorological data, the ISCST3 model calculates hourly and annual ambient impacts for each pollutant. As mentioned above, the modeled 1-hour, 3-hour, 8-hour, and 24-hour ambient impacts are based on the worst-case daily emission rates of NOx, SO_2, CO, and PM_{10}. The annual impacts are based on the annual emission rates of these pollutants.

The one-hour and annual average concentrations of NO_2 were computed following the revised EPA guidance for computing these concentrations (August 9, 1995 *Federal Register*, 60 FR 40465), which is implemented in the ISC_OLM model. Concurrent ozone data collected at Morro Bay was used in the analysis.

The modeling analysis results are shown in Table 6.2-5.4. Also included in the table are the maximum background levels that have occurred in the last 3 years and the resulting total ambient impacts. As shown in Table 6.2-5.4, with the exception of 24-hour and annual PM_{10} impacts, construction impacts alone for all modeled pollutants are expected to be below the most stringent state and national standards. However, the state 24-hour average PM_{10} standard is exceeded in the absence of the construction emissions for the Project.

The ISCST3 model overpredicts PM_{10} construction emission impacts due to the cold plume (i.e., ambient temperature) effect of dust emissions. Most of the plume dispersion characteristics in the ISCST3 model are derived from observations of hot plumes associated with typical smoke stacks. The ISCST3 model does compensate for plume temperature; however, for ambient temperature plumes the model assumes negligible buoyancy and dispersion. Consequently, the ambient concentrations in cold plumes remain high even at significant distances from a source. The Project construction site impacts are not unusual in comparison to most construction sites; construction sites that use good dust suppression techniques and low-emitting vehicles typically do not cause violations of air quality standards. The input and output modeling files are being provided electronically.

TABLE 6.2-5.4
MODELED MAXIMUM CONSTRUCTION IMPACTS

POLLU-TANT	AVERAGIN G TIME	MAXIMUM CONSTRUC-TION IMPACTS ($\mu g/m^3$)	BACK-GROUND ($\mu g/m^3$)	TOTAL IMPACT ($\mu g/m^3$)	STANDARD ($\mu g/m^3$)	FEDERAL STANDARD ($\mu g/m^3$)
NO_2[1]	1-hour	346.8	122	469	470	--
	Annual	31.1	25	56.1	--	100
SO_2	1-hour	99.7	106	205.7	650	--
	24-hour	20.8	13	33.8	109	365
	Annual	4.7	0	4.7	--	80
CO	1-hour	6,464.6	6,988	13,453	23,000	40,000
	8-hour	3,488.6	3,444	6,933	10,000	10,000
PM_{10}	24-hour	116.6	57	173.6	50	150
	Annual[2]	35.3	20.6	55.9	30	--
	Annual[3]	35.3	18.6	53.9	--	50

Notes: 1. ISC_OLM used to model NO_2.
2. Annual Arithmetic Mean.
3. Annual Geometric Mean.
4. Based on maximum daily emissions during Month 10.
5. Based on maximum daily emissions during Month 5.

6.2-5.5.4 HEALTH RISK OF DIESEL EXHAUST

The combustion portion of annual PM_{10} emissions from Table 6.2-5.3 above were modeled separately to determine the annual average Diesel PM_{10} exhaust concentration. This was used with the ARB-approved unit risk value of 300 in one million for a 70-year lifetime to determine the potential carcinogenic risk from Diesel exhaust during construction. The exposure was also adjusted by a factor of 1.67/70, or 0.0238, to correct for the 20-month exposure.

The maximum modeled annual average concentration of Diesel exhaust PM_{10} in residential areas is 0.68 ug/m^3. Using the unit risk value and adjustment factors described above, the carcinogenic risk due to exposure to Diesel exhaust during construction activities is expected to be under 5 in one million. This is well below the 10 in one million level considered to be significant.

This analysis is overly conservative for several reasons. First, as discussed above, the modeled PM_{10} concentrations from construction operations are overpredicted by the ISCST3 model. Second, this analysis assumes that all of the combustion PM_{10} is emitted by Diesel engines, when in fact some of the engines will be gasoline-fueled and thus will not produce Diesel particulate.

ATTACHMENT 6.2-5.1
DETAILED CONSTRUCTION EMISSIONS CALCULATIONS

Construction Equipment Daily Exhaust Emissions
New Generation Project (Month 5)

Equipment	Equipment Rating	Units	Load Factor	Number of Units	Hrs/Day Per Unit	Emission Factors (1) NOx	CO	VOC	SOx	PM10	Units	Daily Emissions (lbs/day) NOx	CO	VOC	SOx	PM10
Front end loader/backhoe	150	bhp	0.38	3	7	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	18.21	2.64	1.06	0.48	1.06
Dozer tractor crawler	100	bhp	0.57	1	7	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	6.07	0.88	0.35	0.16	0.35
Trenching machine	20	bhp	0.64	1	6	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	1.17	0.17	0.07	0.03	0.07
Grader	100	bhp	0.54	1	7	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	5.75	0.83	0.33	0.15	0.33
Tamper, gasoline	4	bhp	0.43	2	6	2.0	353.0	19.1	0.0	0.1	gm/bhp-hr	0.09	16.06	0.87	0.00	0.00
Vibrating plate compactor, gasolin	8	bhp	0.43	2	6	2.0	353.0	19.1	0.0	0.1	gm/bhp-hr	0.18	32.12	1.74	0.00	0.01
Roller vibrator	100	bhp	0.59	0	6	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	0.00	0.00	0.00	0.00	0.00
Water truck	150	bhp	0.65	1	6	3.4	2.6	0.4	0.2	0.2	gm/bhp-hr	4.33	3.36	0.51	0.24	0.28
Concrete mixer, gasoline	20	bhp	0.45	1	3	2.0	353.0	19.1	0.0	0.1	gm/bhp-hr	0.12	21.01	1.14	0.00	0.00
Concrete pump	50	bhp	0.45	0	3	8.0	5.0	1.2	0.2	1.0	gm/bhp-hr	0.00	0.00	0.00	0.00	0.00
Mortar mixer, gasoline	11	bhp	0.45	0	4	2.0	353.0	19.1	0.0	0.1	gm/bhp-hr	0.00	0.00	0.00	0.00	0.00
Concrete transit truck	250	bhp	0.65	0	4	3.4	2.6	0.4	0.2	0.2	gm/bhp-hr	0.00	0.00	0.00	0.00	0.00
Paving machine	100	bhp	0.56	0	5	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	0.00	0.00	0.00	0.00	0.00
Dump trucks	235	bhp	0.65	2	7	3.4	2.6	0.4	0.2	0.2	gm/bhp-hr	15.83	12.27	1.85	0.86	1.03
Crane (6 ton)	30	bhp	0.43	1	7	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	1.37	0.20	0.08	0.04	0.08
Crane (20 ton)	125	bhp	0.43	2	7	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	11.45	1.66	0.66	0.30	0.66
Crane (50 ton)	175	bhp	0.43	2	7	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	16.03	2.32	0.93	0.42	0.93
Crane (65 ton)	250	bhp	0.43	0	7	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	0.00	0.00	0.00	0.00	0.00
Crane (100 ton)	270	bhp	0.43	0	6	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	0.00	0.00	0.00	0.00	0.00
Manlift	66	bhp	0.55	0	4	8.0	5.0	1.2	0.2	1.0	gm/bhp-hr	0.00	0.00	0.00	0.00	0.00
Welder (250 amp)	35	bhp	0.45	2	6	8.0	5.0	1.2	0.2	1.0	gm/bhp-hr	3.33	2.08	0.50	0.08	0.42
Air compressor (185 cfm)	50	bhp	0.48	1	6	8.0	5.0	1.2	0.2	1.0	gm/bhp-hr	2.54	1.59	0.38	0.06	0.32
Air compressor, (375 cfm)	115	bhp	0.48	1	8	8.0	5.0	1.2	0.2	1.0	gm/bhp-hr	7.79	4.87	1.17	0.18	0.97
Air compressor (750 cfm)	250	bhp	0.48	0	8	8.0	5.0	1.2	0.2	1.0	gm/bhp-hr	0.00	0.00	0.00	0.00	0.00
Generator (6 kW)	30	bhp	0.74	2	8	8.0	5.0	1.2	0.2	1.0	gm/bhp-hr	6.26	3.92	0.94	0.14	0.78
Forklift, gasoline (2 ton)	62	bhp	0.3	1	6	2.0	353.0	19.1	0.0	0.1	gm/bhp-hr	0.50	86.85	4.71	0.00	0.01
Forklift (4 ton)	83	bhp	0.3	0	6	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	0.00	0.00	0.00	0.00	0.00
Fuel/lube truck	260	bhp	0.65	1	4	3.4	2.6	0.4	0.2	0.2	gm/bhp-hr	5.00	3.88	0.59	0.27	0.33
Pickup truck, ½-ton 2WD	0.83	gal/hr	N/A	3	5	62.7	59.9	5.7	7.1	5.0	lbs/1000 gal	0.78	0.75	0.07	0.09	0.06
Pickup truck, ½-ton 4WD	0.83	gal/hr	N/A	1	5	62.7	59.9	5.7	7.1	5.0	lbs/1000 gal	0.26	0.25	0.02	0.03	0.02
Stakebed truck	1.66	gal/hr	N/A	1	6	62.7	59.9	5.7	7.1	5.0	lbs/1000 gal	0.62	0.60	0.06	0.07	0.05
Boom truck	1.66	gal/hr	N/A	1	4	62.7	59.9	5.7	7.1	5.0	lbs/1000 gal	0.42	0.40	0.04	0.05	0.03
Hydrotest pump	23	bhp	0.74	0	3	8.0	5.0	1.2	0.2	1.0	gm/bhp-hr	0.00	0.00	0.00	0.00	0.00
Pump, gasoline (150 gpm)	5	bhp	0.74	2	2	2.0	353.0	19.1	0.0	0.1	gm/bhp-hr	0.07	11.52	0.62	0.00	0.00
Pump, gasoline (600 gpm)	20	bhp	0.74	2	2	2.0	353.0	19.1	0.0	0.1	gm/bhp-hr	0.26	46.07	2.50	0.00	0.01
Light tower (4 kW)	20	bhp	0.51	2	4	8.0	5.0	1.2	0.2	1.0	gm/bhp-hr	1.44	0.90	0.22	0.03	0.18
80 Ton crane	250	bhp	0.43	0	7	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	0.00	0.00	0.00	0.00	0.00
300 Ton crane	450	bhp	0.43	0	7	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	0.00	0.00	0.00	0.00	0.00
360 Ton crane	450	bhp	0.43	0	7	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	0.00	0.00	0.00	0.00	0.00
500 Ton crane	685	bhp	0.43	0	8	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	0.00	0.00	0.00	0.00	0.00
Front-end Loader	116	bhp	0.38	1	7	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	4.69	0.68	0.27	0.12	0.27
Forklift (3 ton), gasoline	47	bhp	0.3	0	6	2.0	353.0	19.1	0.0	0.1	gm/bhp-hr	0.00	0.00	0.00	0.00	0.00
Pickup (3/4 ton)	0.83	gal/hr	N/A	1	4	62.7	59.9	5.7	7.1	5.0	lbs/1000 gal	0.21	0.20	0.02	0.02	0.02
Semi-tractor	310	bhp	0.5	0	5	3.4	2.6	0.4	0.2	0.2	gm/bhp-hr	0.00	0.00	0.00	0.00	0.00
Bobcat skip loader	70	bhp	0.38	2	6	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	4.86	0.70	0.28	0.13	0.28
Total =												119.63	258.76	21.97	3.95	8.57

Notes:
(1) See notes on combustion emissions.

Construction Equipment Daily Exhaust Emissions
New Generation Project (Month 10)

Equipment	Equipment Rating	Units	Load Factor	Number of Units	Hrs/Day Per Unit	ssion Factors (1) NOx	CO	VOC	SOx	PM10	Units	Daily Emissions (lbs/day) NOx	CO	VOC	SOx	PM10
Front end loader/backhoe	150	bhp	0.38	2	7	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	12.14	1.76	0.70	0.32	0.70
Dozer tractor crawler	100	bhp	0.57	0	7	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	0.00	0.00	0.00	0.00	0.00
Trenching machine	20	bhp	0.64	0	6	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	0.00	0.00	0.00	0.00	0.00
Grader	100	bhp	0.54	0	7	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	0.00	0.00	0.00	0.00	0.00
Tamper, gasoline	4	bhp	0.43	4	6	2.0	353.0	19.1	0.0	0.1	gm/bhp-hr	0.18	32.12	1.74	0.00	0.01
Vibrating plate compactor, gasolin	8	bhp	0.43	4	6	2.0	353.0	19.1	0.0	0.1	gm/bhp-hr	0.37	64.25	3.48	0.00	0.01
Roller vibrator	100	bhp	0.59	2	6	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	10.77	1.56	0.62	0.28	0.62
Water truck	150	bhp	0.65	1	6	3.4	2.6	0.4	0.2	0.2	gm/bhp-hr	4.33	3.36	0.51	0.24	0.28
Concrete mixer, gasoline	20	bhp	0.45	1	3	2.0	353.0	19.1	0.0	0.1	gm/bhp-hr	0.12	21.01	1.14	0.00	0.00
Concrete pump	50	bhp	0.45	1	3	8.0	5.0	1.2	0.2	1.0	gm/bhp-hr	1.19	0.74	0.18	0.03	0.15
Mortar mixer, gasoline	11	bhp	0.45	2	4	2.0	353.0	19.1	0.0	0.1	gm/bhp-hr	0.18	30.82	1.67	0.00	0.01
Concrete transit truck	250	bhp	0.65	4	4	3.4	2.6	0.4	0.2	0.2	gm/bhp-hr	19.24	14.92	2.25	1.05	1.26
Paving machine	100	bhp	0.56	0	5	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	0.00	0.00	0.00	0.00	0.00
Dump trucks	235	bhp	0.65	2	7	3.4	2.6	0.4	0.2	0.2	gm/bhp-hr	15.83	12.27	1.85	0.86	1.03
Crane (6 ton)	30	bhp	0.43	1	7	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	1.37	0.20	0.08	0.04	0.08
Crane (20 ton)	125	bhp	0.43	3	7	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	17.17	2.49	1.00	0.45	1.00
Crane (50 ton)	175	bhp	0.43	4	7	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	32.05	4.65	1.86	0.84	1.86
Crane (65 ton)	250	bhp	0.43	2	7	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	22.89	3.32	1.33	0.60	1.33
Crane (100 ton)	270	bhp	0.43	1	6	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	10.60	1.54	0.61	0.28	0.61
Manlift	66	bhp	0.55	2	4	8.0	5.0	1.2	0.2	1.0	gm/bhp-hr	5.12	3.20	0.77	0.12	0.64
Welder (250 amp)	35	bhp	0.45	5	6	8.0	5.0	1.2	0.2	1.0	gm/bhp-hr	8.33	5.21	1.25	0.19	1.04
Air compressor (185 cfm)	50	bhp	0.48	2	6	8.0	5.0	1.2	0.2	1.0	gm/bhp-hr	5.08	3.17	0.76	0.12	0.63
Air compressor, (375 cfm)	115	bhp	0.48	1	8	8.0	5.0	1.2	0.2	1.0	gm/bhp-hr	7.79	4.87	1.17	0.18	0.97
Air compressor (750 cfm)	250	bhp	0.48	1	8	8.0	5.0	1.2	0.2	1.0	gm/bhp-hr	16.93	10.58	2.54	0.38	2.12
Generator (6 kW)	30	bhp	0.74	2	8	8.0	5.0	1.2	0.2	1.0	gm/bhp-hr	6.26	3.92	0.94	0.14	0.78
Forklift, gasoline (2 ton)	62	bhp	0.3	2	6	2.0	353.0	19.1	0.0	0.1	gm/bhp-hr	1.00	173.70	9.41	0.00	0.03
Forklift (4 ton)	83	bhp	0.3	3	6	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	6.82	0.99	0.40	0.18	0.40
Fuel/lube truck	260	bhp	0.65	2	4	3.4	2.6	0.4	0.2	0.2	gm/bhp-hr	10.00	7.76	1.17	0.55	0.65
Pickup truck, ½-ton 2WD	0.83	gal/hr	N/A	6	5	62.7	59.9	5.7	7.1	5.0	lbs/1000 gal	1.56	1.49	0.14	0.18	0.12
Pickup truck, ½-ton 4WD	0.83	gal/hr	N/A	2	5	62.7	59.9	5.7	7.1	5.0	lbs/1000 gal	0.52	0.50	0.05	0.06	0.04
Stakebed truck	1.66	gal/hr	N/A	2	6	62.7	59.9	5.7	7.1	5.0	lbs/1000 gal	1.25	1.19	0.11	0.14	0.10
Boom truck	1.66	gal/hr	N/A	1	4	62.7	59.9	5.7	7.1	5.0	lbs/1000 gal	0.42	0.40	0.04	0.05	0.03
Hydrotest pump	23	bhp	0.74	0	3	8.0	5.0	1.2	0.2	1.0	gm/bhp-hr	0.00	0.00	0.00	0.00	0.00
Pump, gasoline (150 gpm)	5	bhp	0.74	2	2	2.0	353.0	19.1	0.0	0.1	gm/bhp-hr	0.07	11.52	0.62	0.00	0.00
Pump, gasoline (600 gpm)	20	bhp	0.74	1	2	2.0	353.0	19.1	0.0	0.1	gm/bhp-hr	0.13	23.04	1.25	0.00	0.00
Light tower (4 kW)	20	bhp	0.51	3	4	8.0	5.0	1.2	0.2	1.0	gm/bhp-hr	2.16	1.35	0.32	0.05	0.27
80 Ton crane	250	bhp	0.43	0	7	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	0.00	0.00	0.00	0.00	0.00
300 Ton crane	450	bhp	0.43	0	7	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	0.00	0.00	0.00	0.00	0.00
360 Ton crane	450	bhp	0.43	0	7	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	0.00	0.00	0.00	0.00	0.00
500 Ton crane	685	bhp	0.43	0	8	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	0.00	0.00	0.00	0.00	0.00
Front-end Loader	116	bhp	0.38	1	7	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	4.69	0.68	0.27	0.12	0.27
Forklift (3 ton), gasoline	47	bhp	0.3	1	6	2.0	353.0	19.1	0.0	0.1	gm/bhp-hr	0.38	65.84	3.57	0.00	0.01
Pickup (3/4 ton)	0.83	gal/hr	N/A	1	4	62.7	59.9	5.7	7.1	5.0	lbs/1000 gal	0.21	0.20	0.02	0.02	0.02
Semi-tractor	310	bhp	0.5	1	5	3.4	2.6	0.4	0.2	0.2	gm/bhp-hr	5.74	4.45	0.67	0.31	0.38
Bobcat skip loader	70	bhp	0.38	4	6	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	9.71	1.41	0.56	0.26	0.56
Total =												242.60	520.43	45.07	8.02	18.03

Notes:
(1) See notes on combustion emissions.

Construction Equipment Annual Exhaust Emissions
New Generation Project

Equipment	Average Number of Units Per Year	Equipment Rating	Units	Load Factor	Average Operating Hrs/Day	Average Operating Days/Yr	Emission Factors (1) NOx	CO	VOC	SOx	PM10	Units	Annual Emissions (tons/yr) NOx	CO	VOC	SOx	PM10
Front end loader/backhoe	1.667	150	bhp	0.38	7	250	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	1.3	0.2	0.1	0.0	0.1
Dozer tractor crawler	0.000	100	bhp	0.57	7	250	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	0.0	0.0	0.0	0.0	0.0
Trenching machine	0.083	20	bhp	0.64	6	250	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	0.0	0.0	0.0	0.0	0.0
Grader	0.000	100	bhp	0.54	7	250	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	0.0	0.0	0.0	0.0	0.0
Tamper, gasoline	2.333	4	bhp	0.43	6	250	2.0	353.0	19.1	0.0	0.1	gm/bhp-hr	0.0	2.3	0.1	0.0	0.0
Vibrating plate compactor, gasolin	2.667	8	bhp	0.43	6	250	2.0	353.0	19.1	0.0	0.1	gm/bhp-hr	0.0	5.4	0.3	0.0	0.0
Roller vibrator	1.000	100	bhp	0.59	6	250	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	0.7	0.1	0.0	0.0	0.0
Water truck	1.000	150	bhp	0.65	6	250	3.4	2.6	0.4	0.2	0.2	gm/bhp-hr	0.5	0.4	0.1	0.0	0.0
Concrete mixer, gasoline	0.833	20	bhp	0.45	3	250	2.0	353.0	19.1	0.0	0.1	gm/bhp-hr	0.0	2.2	0.1	0.0	0.0
Concrete pump	0.583	50	bhp	0.45	3	250	8.0	5.0	1.2	0.2	1.0	gm/bhp-hr	0.1	0.1	0.0	0.0	0.0
Mortar mixer, gasoline	1.167	11	bhp	0.45	4	250	2.0	353.0	19.1	0.0	0.1	gm/bhp-hr	0.0	2.2	0.1	0.0	0.0
Concrete transit truck	1.500	250	bhp	0.65	4	250	3.4	2.6	0.4	0.2	0.2	gm/bhp-hr	0.9	0.7	0.1	0.0	0.1
Paving machine	0.167	100	bhp	0.56	5	250	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	0.1	0.0	0.0	0.0	0.0
Dump trucks	1.500	235	bhp	0.65	7	250	3.4	2.6	0.4	0.2	0.2	gm/bhp-hr	1.5	1.2	0.2	0.1	0.1
Crane (6 ton)	0.833	30	bhp	0.43	7	250	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	0.1	0.0	0.0	0.0	0.0
Crane (20 ton)	2.417	125	bhp	0.43	7	250	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	1.7	0.3	0.1	0.0	0.1
Crane (50 ton)	2.667	175	bhp	0.43	7	250	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	2.7	0.4	0.2	0.1	0.2
Crane (65 ton)	1.250	250	bhp	0.43	7	250	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	1.8	0.3	0.1	0.0	0.1
Crane (100 ton)	0.667	270	bhp	0.43	6	250	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	0.9	0.1	0.1	0.0	0.1
Manlift	1.583	66	bhp	0.55	4	250	8.0	5.0	1.2	0.2	1.0	gm/bhp-hr	0.5	0.3	0.1	0.0	0.1
Welder (250 amp)	3.667	35	bhp	0.45	6	250	8.0	5.0	1.2	0.2	1.0	gm/bhp-hr	0.8	0.5	0.1	0.0	0.1
Air compressor (185 cfm)	1.333	50	bhp	0.48	6	250	8.0	5.0	1.2	0.2	1.0	gm/bhp-hr	0.4	0.3	0.1	0.0	0.1
Air compressor, (375 cfm)	1.000	115	bhp	0.48	8	250	8.0	5.0	1.2	0.2	1.0	gm/bhp-hr	1.0	0.6	0.1	0.0	0.1
Air compressor (750 cfm)	0.917	250	bhp	0.48	8	250	8.0	5.0	1.2	0.2	1.0	gm/bhp-hr	1.9	1.2	0.3	0.0	0.2
Generator (6 kW)	2.083	30	bhp	0.74	8	250	8.0	5.0	1.2	0.2	1.0	gm/bhp-hr	0.8	0.5	0.1	0.0	0.1
Forklift, gasoline (2 ton)	1.250	62	bhp	0.3	6	250	2.0	353.0	19.1	0.0	0.1	gm/bhp-hr	0.1	13.6	0.7	0.0	0.0
Forklift (4 ton)	2.083	83	bhp	0.3	6	250	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	0.6	0.1	0.0	0.0	0.0
Fuel/lube truck	1.167	260	bhp	0.65	4	250	3.4	2.6	0.4	0.2	0.2	gm/bhp-hr	0.7	0.6	0.1	0.0	0.0
Pickup truck, ½-ton 2WD	5.333	0.83	gal/hr	N/A	5	250	62.7	59.9	5.7	7.1	5.0	lbs/1000 gal	0.2	0.2	0.0	0.0	0.0
Pickup truck, ½-ton 4WD	2.000	0.83	gal/hr	N/A	5	250	62.7	59.9	5.7	7.1	5.0	lbs/1000 gal	0.1	0.1	0.0	0.0	0.0
Stakebed truck	1.667	1.66	gal/hr	N/A	6	250	62.7	59.9	5.7	7.1	5.0	lbs/1000 gal	0.1	0.1	0.0	0.0	0.0
Boom truck	1.000	1.66	gal/hr	N/A	4	250	62.7	59.9	5.7	7.1	5.0	lbs/1000 gal	0.1	0.0	0.0	0.0	0.0
Hydrotest pump	0.417	23	bhp	0.74	3	250	8.0	5.0	1.2	0.2	1.0	gm/bhp-hr	0.0	0.0	0.0	0.0	0.0
Pump, gasoline (150 gpm)	1.833	5	bhp	0.74	2	250	2.0	353.0	19.1	0.0	0.1	gm/bhp-hr	0.0	1.3	0.1	0.0	0.0
Pump, gasoline (600 gpm)	1.167	20	bhp	0.74	2	250	2.0	353.0	19.1	0.0	0.1	gm/bhp-hr	0.0	3.4	0.2	0.0	0.0
Light tower (4 kW)	2.083	20	bhp	0.51	4	250	8.0	5.0	1.2	0.2	1.0	gm/bhp-hr	0.2	0.1	0.0	0.0	0.0
80 Ton crane	0.333	250	bhp	0.43	7	250	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	0.5	0.1	0.0	0.0	0.0
300 Ton crane	0.250	450	bhp	0.43	7	250	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	0.6	0.1	0.0	0.0	0.0
360 Ton crane	0.333	450	bhp	0.43	7	250	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	0.9	0.1	0.0	0.0	0.0
500 Ton crane	0.083	685	bhp	0.43	8	250	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	0.4	0.1	0.0	0.0	0.0
Front-end Loader	1.000	116	bhp	0.38	7	250	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	0.6	0.1	0.0	0.0	0.0
Forklift (3 ton), gasoline	0.917	47	bhp	0.3	6	250	2.0	353.0	19.1	0.0	0.1	gm/bhp-hr	0.0	7.5	0.4	0.0	0.0
Pickup (3/4 ton)	1.250	0.83	gal/hr	N/A	4	250	62.7	59.9	5.7	7.1	5.0	lbs/1000 gal	0.0	0.0	0.0	0.0	0.0
Semi-tractor	0.667	310	bhp	0.5	5	250	3.4	2.6	0.4	0.2	0.2	gm/bhp-hr	0.5	0.4	0.1	0.0	0.0
Bobcat skip loader	2.500	70	bhp	0.38	6	250	6.9	1.0	0.4	0.2	0.4	gm/bhp-hr	0.8	0.1	0.0	0.0	0.0
Total =													24.1	47.1	4.2	0.8	1.8

Notes:
(1) See notes on combustion emissions.

Delivery Truck Daily Emissions (Month 5)
Morro Bay Power Plant

Project	Number of Deliveries Per Day	Average Round Trip Haul Distance (miles)	Vehicle Miles Traveled Per Day	Emission Factors (lbs/vmt)(1) NOx	CO	VOC	SOx	PM10	Daily Emissions (lbs/day) NOx	CO	VOC	SOx	PM10
New Generation Project	17	73.2	1244.4	0.0214	0.0166	0.0025	0.0012	0.0014	26.67	20.67	3.12	1.45	1.74

Notes:
(1) See notes for combustion emissions.

Delivery Truck Daily Emissions (Month 10)
Morro Bay Power Plant

Project	Number of Deliveries Per Day	Average Round Trip Haul Distance (miles)	Vehicle Miles Traveled Per Day	Emission Factors (lbs/vmt)(1) NOx	CO	VOC	SOx	PM10	Daily Emissions (lbs/day) NOx	CO	VOC	SOx	PM10
New Generation Project	17	73.2	1244.4	0.0214	0.0166	0.0025	0.0012	0.0014	26.67	20.67	3.12	1.45	1.74

Notes:
(1) See notes for combustion emissions.

Delivery Truck Annual Emissions
Morro Bay Power Plant

Project	Average Number of Deliveries Per Year	Average Round Trip Haul Distance (miles)	Vehicle Miles Traveled Per Year	Emission Factors (lbs/vmt)(1) NOx	CO	VOC	SOx	PM10	Annual Emissions (tons/yr) NOx	CO	VOC	SOx	PM10
New Generation Project	750	73.2	54,900	0.0214	0.0166	0.0025	0.0012	0.0014	0.59	0.46	0.07	0.03	0.04
Tank Demolition Project	198	73.2	14,494	0.0214	0.0166	0.0025	0.0012	0.0014	0.16	0.12	0.02	0.01	0.01
Total =									0.74	0.58	0.09	0.04	0.05

Notes:
(1) See notes for combustion emissions.

Delivery Truck Idling Emissions
Morro Bay Power Plant

Project	Maximum Number of Truck Deliveries Per Day	Maximum Idling Time Per Truck Delivery (hrs)	Total Maximum Delivery Truck Idling Time Per Day (hrs/day)	PM10 Emission Factor(1) (lbs/hr)	Maximum Daily PM10 Delivery Truck Emissions (lbs/day)	Maximum Annual PM10 Delivery Truck Emissions(2) (tons/yr)
New Generation Project	17	1	17	0.004	0.072	0.013
Tank Demolition Project	16	1	16	0.004	0.067	0.002
Total =					0.139	0.015

Notes:
(1) Based on 1.91 g/hr idle emission rate for the composite HDD truck fleet in 2001 from EPA's PART5 model.
(2) For new generation project based on 365 days per year of operation. For tank demoliton project based on 66 days per year of operation.

Rail Delivery Daily Emissions (Month 10)
Morro Bay Power Plant

Inbound: Number of Railcars per day	Loaded Weight of Railcar (tons)	Total Gross Weight of Railcars (tons)	One-Way Haul Distance(1) (miles)	Unit Fuel Use Factor(2) (gal/KGTM)	Fuel Use (gals)	Outbound: Number of Railcars per day	Tare Weight of Railcar (tons)	Total Gross Weight of Railcars (tons)	One-Way Haul Distance(1) (miles)	Unit Fuel Use Factor(2) (gal/KGTM)	Fuel Use (gals)
4	221.5	886	37.2	1.37	45.1541	4	34	136	37.2	1.37	6.93

Total Fuel Use (gals)	Emission Factors (lbs/1000 gals)(3) NOx	CO	VOC	SOx	PM10	Daily Emissions (lbs/day) NOx	CO	VOC	SOx	PM10
52.09	594.71	58.59	22.03	38.00	14.76	30.98	3.05	1.15	1.98	0.77

Notes:
(1) Distance from plant site along Union Pacific Railroad line to Town of Guadalupe.
(2) Based on Union Pacific Railroad system wide average fuel use factor.
(3) See notes for combustion emissions.

Rail Delivery Annual Emissions
Morro Bay Power Plant

Average Number of Rail Deliveries per Year(1)	Emissions per Delivery (lbs/rail delivery) NOx	CO	VOC	SOx	PM10	Annual Emissions (tons/yr) NOx	CO	VOC	SOx	PM10
9.6	30.976	3.052	1.147	1.979	0.769	0.149	0.015	0.006	0.010	0.004

Notes:
(1) Based on total of 12 rail deliveries over a 15-month period.

Worker Travel Daily Emissions (Month 5)
Morro Bay Power Plant

Project	Number of Workers Per Day(1)	Average Vehicle Occupancy (person/veh.)	Number of Round Trips Per Day	Average Round Trip Haul Distance (Miles)	Vehicle Miles Traveled Per Day (Miles)	Emission Factors (lbs/vmt)(2)					Daily Emissions (lbs/day)				
						NOx	CO	VOC	SOx	PM10	NOx	CO	VOC	SOx	PM10
New Generation Project	81	1.16	69.83	73.2	5111.4	0.003	0.030	0.002	1.5E-06	5.9E-05	13.10	153.38	12.54	0.01	0.30

Notes:
(1) Based expected number of construction workers during this phase of construction.
(2) See notes for combustion emissions.

Worker Travel Daily Emissions (Month 10)
Morro Bay Power Plant

Project	Number of Workers Per Day(1)	Average Vehicle Occupancy (person/veh.)	Number of Round Trips Per Day	Average Round Trip Haul Distance (Miles)	Vehicle Miles Traveled Per Day (Miles)	Emission Factors (lbs/vmt)(2)					Daily Emissions (lbs/day)				
						NOx	CO	VOC	SOx	PM10	NOx	CO	VOC	SOx	PM10
New Generation Project	299	1.16	257.758621	73.2	18867.93103	0.002562563	0.03001	0.00245	1.5E-06	5.9E-05	48.3503	566.169	46.2872	0.02906	1.10415

Notes:
(1) Based expected number of construction workers during this phase of construction.
(2) See notes for combustion emissions.

Worker Travel Annual Emissions
Morro Bay Power Plant

Project	Average Number of Workers Per Day(1)	Average Vehicle Occupancy (person/veh.)	Number of Round Trips Per Day	Average Round Trip Haul Distance (Miles)	Days per Year	Vehicle Miles Traveled Per Year	Emission Factors (lbs/vmt)(2)					Annual Emissions (tons/yr)				
							NOx	CO	VOC	SOx	PM10	NOx	CO	VOC	SOx	PM10
New Generation Project	418	1.16	360.34	73.2	250	6,594,310.34	0.00256	0.03001	0.00245	1.5E-06	5.9E-05	8.45	98.94	8.09	0.01	0.19
Tank Demolition Project	17	1.16	14.66	73.2	0	0	0.00256	0.03001	0.00245	1.5E-06	5.9E-05	0	0	0	0	0
Total =												8.45	98.94	8.09	0.01	0.19

Notes:
(1) Based on average during construction period.
(2) See notes for combustion emissions.

Daily Fugitive Dust Emissions
New Generation Project (Month 5)

Equipment	Number of Units	Daily Process Rate Per Unit	Total Process Rate	Units	PM10 Emission Factor(1) (lbs/unit)	Control Factor(1) (%)	PM10 Emissions (lbs/day)
Front end loader/backhoe - excavation	4	600.0	2400.0	cu. yds.	0.00		4.39
Front end loader/backhoe - unpaved road travel	4	24.7	98.9	vmt	0.11	88%	1.27
Bobcat - excavation	2	74.7	149.4	cu. yds.	0.00		0.27
Bobcat - unpaved road travel	2	24.7	49.5	vmt	0.06	88%	0.36
Dozer tractor crawler - excavation	1	7.0	7.0	hours	0.75		5.27
Trenching machine - excavation	1	1640.4	1640.4	cu. yds.	0.00		3.00
Grader	1	21.0	21.0	vmt	0.28		5.78
Water trucks - unpaved road travel	1	18.0	18.0	vmt	0.15	88%	0.32
Transit mix trucks - unpaved road travel	0	3.9	0.0	vmt	0.16	88%	0.00
Dump trucks - unloading	2	600.0	1200.0	tons	0.00		0.25
Dump trucks - unpaved road travel	2	8.3	16.7	vmt	0.16	88%	0.31
Forklift (2 ton) - unpaved road travel	1	12.3	12.3	vmt	0.10	88%	0.14
Forklift (4 ton) - unpaved road travel	0	12.3	0.0	vmt	0.10	88%	0.00
Forklift (3 ton) - unpaved road travel	0	12.3	0.0	vmt	0.10	88%	0.00
Fuel/lube truck - unpaved road travel	1	1.5	1.5	vmt	0.12	88%	0.02
Pickup truck (½-ton 2WD) - unpaved road travel	4	7.7	30.9	vmt	0.06	88%	0.21
Pickup truck (½-ton 4WD) - unpaved road travel	1	7.7	7.7	vmt	0.06	88%	0.05
Stakebed truck - unpaved road travel	1	3.9	3.9	vmt	0.08	88%	0.04
Boom truck - unpaved road travel	1	3.9	3.9	vmt	0.16	88%	0.07
Windblown dust - active construction area	N/A	492312.0	492312.0	sq.ft.	0.00	88%	1.43
Windblown dust - laydown area	N/A	338068.0	338068.0	sq.ft.	0.00	88%	0.98
Windblown dust - contractor parking	N/A	67470.0	67470.0	sq.ft.	0.00	88%	0.20
Workers - unpaved road travel	195	0.1	19.1	vmt	0.06	88%	0.13
Workers - paved road travel	195	0.2	33.5	vmt	0.00		0.02
Delivery trucks - unpaved road travel	17	0.3	5.4	vmt	0.16	88%	0.10
Delivery trucks - paved road travel	17	0.1	1.7	vmt	0.02		0.03
Total =							24.639794

Notes:
(1) See notes for fugitive dust emission calculations.

Daily Fugitive Dust Emissions
New Generation Project (Month 10)

Equipment	Number of Units	Daily Process Rate Per Unit	Total Process Rate	Units	PM10 Emission Factor(1) (lbs/unit)	Control Factor(1) (%)	PM10 Emissions (lbs/day)
Front end loader/backhoe - excavation	3	600.0	1800.0	cu. yds.	1.83E-03		3.29
Front end loader/backhoe - unpaved road travel	3	24.7	74.2	vmt	0.11	88%	0.95
Bobcat - excavation	4	74.7	298.8	cu. yds.	1.83E-03		0.55
Bobcat - unpaved road travel	4	24.7	98.9	vmt	0.06	88%	0.73
Dozer tractor crawler - excavation	0	7.0	0.0	hours	0.75		0.00
Trenching machine - excavation	0	1640.4	0.0	cu. yds.	1.83E-03		0.00
Grader	0	21.0	0.0	vmt	0.28		0.00
Water trucks - unpaved road travel	1	18.0	18.0	vmt	0.15	88%	0.32
Transit mix trucks - unpaved road travel	4	3.9	15.5	vmt	0.16	88%	0.28
Dump trucks - unloading	2	600.0	1200.0	tons	2.12E-04		0.25
Dump trucks - unpaved road travel	2	8.3	16.7	vmt	0.16	88%	0.31
Forklift (2 ton) - unpaved road travel	2	12.3	24.7	vmt	0.10	88%	0.28
Forklift (4 ton) - unpaved road travel	3	12.3	37.0	vmt	0.10	88%	0.41
Forklift (3 ton) - unpaved road travel	1	12.3	12.3	vmt	0.10	88%	0.14
Fuel/lube truck - unpaved road travel	2	1.5	3.1	vmt	0.12	88%	0.04
Pickup truck (½-ton 2WD) - unpaved road travel	7	7.7	54.1	vmt	0.06	88%	0.37
Pickup truck (½-ton 4WD) - unpaved road travel	2	7.7	15.5	vmt	0.06	88%	0.11
Stakebed truck - unpaved road travel	2	3.9	7.7	vmt	0.08	88%	0.07
Boom truck - unpaved road travel	1	3.9	3.9	vmt	0.16	88%	0.07
Windblown dust - active construction area	N/A	492312.0	492312.0	sq.ft.	2.52E-05	88%	1.43
Windblown dust - laydown area	N/A	338068.0	338068.0	sq.ft.	2.52E-05	88%	0.98
Windblown dust - contractor parking	N/A	67470.0	67470.0	sq.ft.	2.52E-05	88%	0.20
Workers - unpaved road travel	299	0.1	29.3	vmt	0.06	88%	0.20
Workers - paved road travel	299	0.2	51.4	vmt	0.00		0.02
Delivery trucks - unpaved road travel	17	0.3	5.4	vmt	0.16	88%	0.10
Delivery trucks - paved road travel	17	0.1	1.7	vmt	0.02		0.03
Total =							11.13

Notes:
(1) See notes for fugitive dust emission calculations.

Daily Fugitive Dust Emissions
Tank Demolition Project (Month 2)

Equipment	Number of Units	Daily Process Rate Per Unit	Total Process Rate	Units	PM10 Emission Factor(1) (lbs/unit)	Control Factor(1) (%)	PM10 Emissions (lbs/day)
Front end loader/backhoe - excavation	0	513.8	0	cu. yds.	0.002	0%	0.00
Front end loader/backhoe - unpaved road travel	1	35.0	35.03	vmt	0.111	88%	0.45
Dozer tractor crawler - excavation	1	6.0	6	hours	0.753	0%	4.52
Trenching machine - excavation	2	1640.4	3280.9	cu. yds.	0.002	0%	6.00
Grader	0	18.0	0	vmt	0.275	0%	0.00
Water trucks - unpaved road travel	0	18.0	0	vmt	0.152	88%	0.00
Dump trucks - unloading	0	513.8	0	tons	2.12E-04	0%	0.00
Dump trucks - unpaved road travel	0	12.3	0	vmt	0.159	88%	0.00
Articulated trucks - unloading	2	513.8	1027.50	tons	2.12E-04	0%	0.22
Articulated trucks - unpaved road travel	2	12.3	24.55	vmt	0.206	88%	0.58
Forklift - unpaved road travel	1	11.4	11.36	vmt	0.097	88%	0.13
Fuel/lube truck - unpaved road travel	0	2.3	0	vmt	0.118	88%	0.00
Pickup trucks - unpaved road travel	2	11.4	22.73	vmt	0.060	88%	0.16
Scrapper - excavation	1	6.0	6	hours	0.753	0%	4.52
Windblown dust - active construction area	N/A	492,312.0	492,312	sq.ft.	2.52E-05	88%	1.43
Windblown dust - contractor parking	N/A	67,470.0	67,470	sq.ft.	2.52E-05	88%	0.20
Workers - unpaved road travel	20	0.1	1.96	vmt	0.060	88%	0.01
Workers - paved road travel	20	0.2	3.44	vmt	4.76E-04	0%	0.00
Delivery trucks - unpaved road travel	16	0.3	5.11	vmt	0.159	88%	0.09
Delivery trucks - paved road travel	16	0.1	1.57	vmt	0.018	0%	0.03
Total =							18.33

Notes:
(1) See notes for fugitive dust emission calculations.

Annual Fugitive Dust Emissions
Morro Bay Power Plant

Project	Average Daily PM10 Emissions(1) (lbs/day)	Days Per Year	Annual PM10 Emissions (tons/yr)
New Generation Project			
Construction Activities	15.28	250	1.91
Windblown Dust	2.61	365	0.48
Total =			2.39
Tank Demolition Project			
Construction Activities	16.90	66	0.56
Windblown Dust	1.43	66	0.05
Total =			0.60

Notes:
(1) Based on average of daily emissions during construction period.

Daily Construction Emissions (Month 5) Morro Bay Power Plant					
Daily Emissions (lbs/day)					
	NOx	CO	VOC	SOx	PM10
Onsite Combustion					
New Generation Project	119.6	258.8	22.0	3.9	8.6
Onsite Fugitive Dust					
New Generation Project					24.6
Offsite					
Worker Travel	13.1	153.4	12.5	0.0	0.3
Truck Deliveries	26.7	20.7	3.1	1.5	1.7
Rail Deliveries	0	0	0	0	0
Subtotal =	39.8	174.1	15.7	1.5	2.0
Total =	159.4	432.8	37.6	5.4	35.3

Daily Construction Emissions (Month 10) Morro Bay Power Plant					
Daily Emissions (lbs/day)					
	NOx	CO	VOC	SOx	PM10
Onsite Combustion					
New Generation Project	242.60	520.43	45.07	8.02	18.10
Onsite Fugitive Dust					
New Generation Project					11.13
Offsite					
Worker Travel	48.35	566.17	46.29	0.03	1.10
Truck Deliveries	26.67	20.67	3.12	1.45	1.74
Rail Deliveries	30.98	3.05	1.15	1.98	0.77
Subtotal =	105.99	589.89	50.56	3.46	3.62
Total =	348.60	1110.33	95.63	11.49	32.85

Annual Construction Emissions Morro Bay Power Plant					
Annual Emissions (tons/yr)					
	NOx	CO	VOC	SOx	PM10
Onsite Combustion					
New Generation Project	24.09	47.12	4.23	0.76	1.83
Tank Farm Demolition Project	3.97	0.82	0.26	0.11	0.25
Subtotal =	28.06	47.93	4.49	0.87	2.08
Onsite Fugitive Dust					
New Generation Project					2.39
Tank Farm Demolition Project					0.60
Subtotal =	0	0	0	0	2.99
Offsite					
Worker Travel	8.45	98.94	8.09	0.01	0.19
Truck Deliveries	0.74	0.58	0.09	0.04	0.05
Rail Deliveries	0.15	0.01	0.01	0.01	0.00
Subtotal =	9.34	99.53	8.18	0.06	0.25
Total =	37.41	147.46	12.67	0.93	5.31

Notes - Fugitive Dust Emission Calculations

(1) Paved Road Travel - Delivery Trucks and Workers - Source: AP-42, Section 13.2.1, 10/97

E = k(sL/2)^0.65*(W/3)^1.5

k = particle size constant =	0.016 lb/VMT - PM10
sL = silt loading =	0.015 g/m2 (AP-42, page 13.2.1-5, limited access roac
W = auto/pickup truck avg. vehicle weight =	2.4 tons (CARB Area Source Manual, 9/97)
W = delivery truck avg. vehicle weight =	27.50 tons (for heavy duty Diesel trucks)
E = auto/pick truck emission factor =	0.0005 lb/VMT - PM10
E = delivery truck emission factor =	0.0185 lb/VMT - PM10

(2) Wind erosion of active construction area - 'Source: "Improvement of Specific Emission Factors (BACM Project No. 1), Final Report", prepared for South Coast AQMD by Midwest Research Institute, March 1996

Level 2 Emission Factor =	0.011 ton/acre-month
Construction Schedule =	5 days/week
=	1.1 lbs/acre-day
=	0.000025 lbs/scf-day

(3) Finish Grading - Source: AP-42, Table 11.9-2, 1/95

E = (0.60)(0.051)(S^2.0)

S = mean vehicle speed =	3.0 mph (estimated)
E = emission factor =	0.2754 lb/VMT

(4) Bulldozer Operation and Scraper Excavation - Source: AP-42, Table 11.9.2, 1/95

E = (0.75)(s^1.5)/(M^1.4)

s = silt content =	6.9% (AP-42, Table 11.9-3, 1/95, overburden)
M = moisture content =	7.9% (AP-42, Table 11.9-3, 1/95, overburden)
E = emission factor =	0.75 lb/hr

(5) Scraper Travel

W = mean vehicle weight =	73.4 tons empty (651E scraper, Caterpillar Performance Handbook, 10/89)	
=	125.4 tons loaded (651E scraper, Caterpillar Performance Handbook, 10/89)	
=	99.4 tons mean weight	
Daily Scraper Haul Tonnage =	10,972 ton/day (estimated)	
Scraper Load =	52.0 ton (651E scraper, Caterpillar Performance Handbook, 10/89)	
Daily Scraper Loads =	211.00 loads/day	
Daily Scraper Hauling Distance =	0.08 miles/load (estimated)	
Daily Scraper Travel =	32.56 miles/day	

(6) Material Unloading - Source: AP-42, p. 13.2.4-3, 1/95

E = (k)(0.0032)[(U/5)^1.3]/[(M/2)^1.4]

k = particle size constant =	0.35 for PM10
U = average wind speed =	2.73 m/sec (based on onsite wind data)
=	6.10 mph
M = moisture content =	7.9% (AP-42, Table 11.9-3, 1/95, overburden)
E = emission factor =	0.0002 lb/ton

(7) Loader Unpaved Road Travel - Source: AP-42, Section 13.2.2, 1/95

E = (k)[(s/12)^0.8][(W/3)^0.4]/[(M/0.2)^0.3]

k = particle size constant =	2.6	
s = surface silt content =	6.9% (AP-42, Table 11.9-3, 1/95, overburden)	
M = surface moisture content =	7.9% (AP-42, Table 11.9-3, 1/95, overburden)	
W = avg. vehicle weight =	17.13 tons (avg. of loaded and unloaded weights, 950E loader, Caterpillar Performance Handbook, 10/89)	
E = emission factor =	0.11 lb PM10/VMT	
E = emissions factor (Bobcat) =	0.06 lb PM10/VMT (based on 1/4 the weight of loader)	
Soil Density =	1.275 ton/yd3 (Caterpillar Performance Handbook, 10/89)	
Loader Bucket Capacity =	3.75 yd3 (950E loader, Caterpillar Performance Handbook, 10/89)	
=	4.78 ton/load	4.78 ton/load
Daily Soil Transfer Rate =	600 yd3/day (new gen. project)	513.75 yd3/day (tank demo. project)
Daily Soil Transfer Rate =	765 ton/day	655.03 tons/day (tank demo. project)
Daily Loader Trips =	160 loading trips/day	137 loading trips/day
Loading Travel Distance =	816 ft/load (estimated)	1350 ft/load (estimated)
Daily Loader Travel Distance =	130,560 ft/day	184,950 ft/day
=	24.7 mi/day	35.0 mi/day

(8) Backhoe Trenching - Source: AP-42, Table 11.9-2 (dragline operations), 1/95

E = (0.75)(0.0021)(d^0.7)/(M^0.3)

d = drop height =	3 ft (estimated)
M = moisture content =	7.9% (AP-42, Table 11.9-3, 1/95, overburden)
E = emission factor =	0.0018 lb/yd3
Backhoe Excavating Rate =	49.8 yd3/hr (E70B backhoe, Caterpillar Performance Handbook, 10/89)
=	349 yd3/day for 1 backhoe @ 7 hr/day
Bobcat Excavating Rate =	12.45 yd3/hr (assumes 1/4 of backhoe)
	74.7 yd3/day for 1 bobcat @ 6 hrs/day

(9) Excavator Trenching - Source: AP-42, Table 11.9-2 (dragline operations), 1/95

E = (0.75)(0.0021)(d^0.7)/(M^0.3)

d = drop height =	3 ft (estimated)
M = moisture content =	7.9% (AP-42, Table 11.9-3, 1/95, overburden)
E = emission factor =	0.0018 lb/yd3
Excavator Excavating Rate =	427.2 yd3/hr (225D excavator, Caterpillar Performance Handbook, 10/89)
=	1,640 yd3/day for 1 excavator @ 6 hr/day and including load facto

(10) Unpaved Road Travel - Source: AP-42, Section 13.2.2, 9/98.

E = (k)[(s/12)^0.8][(W/3)^0.4]/[(M/0.2)^0.3]

k = particle size constant =	2.6
s = silt fraction =	8.5% (AP-42, Table 11.9-3, 1/95, overburden)
M = surface moisture content =	7.9% (AP-42, Table 11.9-3, 1/95, overburden)
W = water truck avg. veh. weight =	10.0 tons empty (estimated)
=	39.4 tons loaded (estimated with 8,000 gallon water capacity)
=	24.7 tons average
W = fuel truck avg. veh. weight =	8.0 tons empty (estimated)
=	18.2 tons loaded (estimated with 3,000 gallons Diesel fuel capacity)
=	13.1 tons average
W = service truck avg. veh. weight =	5.0 tons (estimated)
W = dump truck avg. veh. weight =	15.0 tons (for heavy duty Diesel trucks)
=	40.0 tons (for heavy duty Diesel trucks)
=	27.5 tons (for heavy duty Diesel trucks)
W = concrete pumper truck avg. veh. wt. =	15.0 tons (for heavy duty Diesel trucks)
=	40.0 tons (for heavy duty Diesel trucks)
=	27.5 tons (for heavy duty Diesel trucks)
W = forklift avg. veh. weight =	8.0 tons empty (estimated)
W = auto/pickup avg. vehicle weight =	2.4 tons (CARB Area Source Manual, 9/97)
W = delivery truck avg. veh. wt. =	27.5 tons (for heavy duty Diesel trucks)
W = scraper avg. veh. wt. =	73.4 tons empty (651E scraper, Caterpillar Performance Handbook, 10/89)
	125.4 tons loaded (651E scraper, Caterpillar Performance Handbook, 10/89)
	99.4 tons mean weight
W = articulated dump truck	52.355 tons (Cat. D400)
E = water truck emission factor =	0.15 lb PM10/VMT
E = fuel truck emission factor =	0.12 lb PM10/VMT
E = service truck emission factor =	0.08 lb PM10/VMT
E = dump truck emission factor =	0.16 lb PM10/VMT
E = concrete pumper truck emiss. factor =	0.16 lb PM10/VMT
E = forklift emiss. factor =	0.10 lb PM10/VMT
E = 5th wheel truck emiss. factor =	0.10 lb PM10/VMT
E = auto/pickup emiss. factor =	0.06 lb PM10/VMT
E = delivery truck emiss. factor =	0.16 lb PM10/VMT
E = scraper emiss. factor =	0.27 lb PM10/VMT
E = articulated truck emiss. factor =	0.21 lb PM10/VMT

(11) Unpaved Road Travel and Active Excavation Area Control - Source: Control of Open Fugitive Dust Sources, U.S EPA, 9/88

C = 100 - (0.8)(p)(d)(t)/(i)

p = potential average hourly daytime evaporation rate =	0.325 mm/hr (EPA document, Figure 3-2, summer)
d = average hourly daytime traffic rate =	129.4 vehicles/hr (estimated)
t = time between watering applications =	0.25 hr/application (estimated)
i = application intensity =	0.7 L/m2 (typical level in EPA document, page 3-23)
C = average watering control efficiency =	88.5%

Notes - Combustion Emission Calculations

(1) For Construction Equipment
For heavy Diesel construction equipment, emission factors based on equipment meeting EPA 1996 off-road Diesel standards and use of CARB low-sulfur fuel.
For heavy Diesel construction equipment and portable equipment, load factors are based on EPA's "Non-road Engine and Vehicle Emission Study Report", 11/91, Table 2-05.
For trucks, depending on size of truck, emissions factors based on MVE17G version 1.0c for heavy-heavy duty or medium duty Diesel trucks, fleet average for calendar year 2000, North Central Coast Air Basin.
For portable equipment, emission factors based on EPA's "Non-road Engine and Vehicle Emission Study Report", 11/91, Table 2-07, for generator sets, welders, pumps, and air compressors less than 50 hp.

(2) For Delivery Trucks
From MVE17G version 1.0c; heavy-heavy duty Diesel trucks, fleet average for calendar year 2000, North Central Coast Air Basin.

(3) For Worker Travel
From MVE17G version 1.0c, average of light duty automobiles and light duty trucks, fleet average for calendar year 2000, North Central Coast Air Basin.

(4) For Rail Deliveries
NOx, CO, VOC, and PM10 emission factors from EPA's "Technical Highlights - Emissions Factors for Locomotives", December 1997.
SOx emission factor from Booz-Allen & Hamilton "Locomotive Emission Study", prepared for CARB, January 1991.

APPENDIX 6.2-6
EVALUATION OF BEST AVAILABLE CONTROL TECHNOLOGY

APPENDIX 6.2-6
EVALUATION OF BEST AVAILABLE CONTROL TECHNOLOGY

To evaluate BACT for the proposed turbines, the guideline for large gas turbines (heat input rating greater than 23 MMBtu/hr) in BAAQMD BACT/TBACT Workbook was reviewed. The relevant BACT determinations for this analysis are shown in Table 6.2-6.1.

TABLE 6.2-6.1
BAAQMD BACT GUIDELINE FOR LARGE GAS TURBINES

POLLUTANT	BACT	TYPICAL TECHNOLOGY
Nitrogen Oxides	1. <5 ppm dry @ 15% O2 2. 5 ppm dry @ 15% O2	1. SCR + Combustion Modifications 2. SCR + Combustion Modifications
Sulfur Dioxide	1. Natural gas fuel	1. Fuel selection
Carbon Monoxide	1. 10 ppm dry @ 15% O2 2. 10 ppm dry @ 15% O2	1. Catalytic oxidation 2. Catalytic oxidation
VOC	1. >50% reduction by weight 2. 50% reduction by weight	1. Catalytic oxidation 2. Catalytic oxidation
PM_{10}	1. Natural gas fuel	1. Fuel selection

Notes: 1. Technologically feasible and cost effective
2. Achieved in practice

The EPA RACT-BACT-LAER Clearinghouse (RBLC) was also consulted to review recent EPA BACT decisions for gas-fired gas turbines. These recent BACT decisions are summarized in Table 6.2-6.2 below. NOx levels shown in these BACT determinations are very high, although EPA has recently stated that the SCONOx technology has demonstrated that 2.5 ppm is achievable in practice. CO levels in this listing are also relatively high, and do not indicate that oxidations catalysts have been considered BACT for CO or VOCs.

Finally, the ARB's BACT Clearinghouse Database was reviewed for recent BACT decisions regarding large gas turbine projects in California. Relevant BACT decisions are summarized in Table 6.2-6.3. NOx levels shown in these determinations are generally around 5 ppm. None of these recent BACT decisions include a determination for CO, and the determinations for VOC include extremely low catalyst efficiencies (5 to 10 percent).

MBPP proposes to use dry low-NOx combustors with selective catalytic reduction oxidation catalysts to achieve a NOx exhaust concentration of 2.5 ppmv or less and a CO exhaust concentration of 6 ppmv or less. The turbines will be fueled with natural gas to minimize SO_2 and PM_{10} emissions.

TABLE 6.2-6.2
GAS TURBINE BACT DETERMINATIONS FOR EPA RBLC CLEARINGHOUSE

FACILITY/LOCATION	DATE PERMIT ISSUED	EQUIPMENT/RATING	NOX LIMIT/CONTROL TECHNOLOGY	CO LIMIT/CONTROL TECHNOLOGY
Alabama Power Company McIntosh, AL	7/10/97	100 MW combustion turbine w/ duct burner	15 ppm (dry low-NOx burners)	n/a
Lordsburg L.P. Lordsburg, NM	6/18/97	100 MW combustion turbine	15 ppm (dry low-NOx technology)	50 ppm (dry low-NOx technology)
Mead Coated Board, Inc. Phenix City, AL	3/12/97	25 MW combustion turbine w/ fired HRSG	25 ppm (dry low-NOx combustor)	28 ppm (proper design and good combustion practices)
Northern California Power Agency Lodi, CA	10/02/97	GE Frame 5 gas turbine	25 ppm	n/a
Portside Energy Corp. Portage, IN	5/13/96	63 MW gas turbine w/ unfired HRSG	n/a	10 ppm (good combustion)
Southwestern Public Service Hobbs, NM	2/15/97	gas turbine	15 ppm w/o power augmentation 25 ppm w/ augmentation	good combustion practices

TABLE 6.2-6.3
SUMMARY OF BACT DETERMINATIONS FROM ARB BACT CLEARINGHOUSE

FACILITY/DISTRICT	PERMIT NO.	EQUIPMENT/RATING	NOX LIMIT/CONTROL TECHNOLOGY	VOC/HC LIMIT/CONTROL TECHNOLOGY
Sacramento Cogeneration Authority Sacramento Metropolitan AQMD	A330-849-98 A330-850-98 A330-851-98	GE LM6000 combined-cycle gas turbine w/ supplemental firing (42 MW each)	5 ppm (dry low-NOx combustion and SCR)	oxidation catalyst (10% destruction efficiency)
Sacramento Power Authority Sacramento Metropolitan AQMD	A330-852-98	Siemens V84.2 combined-cycle gas turbine w/ supplemental firing (103 MW)	3 ppm (water injection and SCR)	oxidation catalyst (5% destruction efficiency)
Carson Energy Sacramento Metropolitan AQMD	A330-854-98	GE LM6000 combined-cycle gas turbine w/ supplemental firing (42 MW)	5 ppm (water injection and SCR)	oxidation catalyst (10% destruction efficiency)
SEPCO	A330-855-98	GE Frame 7EA gas turbine w/ supplemental firing (82 MW)	5 ppm (dry low-NOx combustion and SCR)[1]	oxidation catalyst (5% destruction efficiency)

Note: 1. District indicates that applicant proposed 2.6 ppm to lower offset liability.

These pollutant levels will achieve emission reductions consistent with the BAAQMD BACT guideline.

6.2-6.2 TOP-DOWN BACT ANALYSIS FOR NOx

Best Available Control Technology (BACT) is defined in San Luis Obispo County APCD Rule 105.A.9 as:

The most stringent emission limitation or control technique which:

- *a.* *has been achieved in practice for such permit unit category or class or source; or*
- *b.* *is contained in any state implementation plan (SIP) approved by the United States Environmental Protection Agency (EPA) for such permit unit category or class of source. A specific limitation or control technique shall not apply if the owner or operator of the proposed permit unit demonstrates to the satisfaction of the Air Pollution Control Officer that such limitation or control technique is not presently achievable; or*
- *c.* *is any other emission limitation or control technique, including process and equipment changes of basic and control equipment, found by the Air Pollution Control Officer to be technologically feasible for such class or category of sources or for a specific source, and cost-effective as compared to measures as listed in the Clean Air Plan (CAP) or rules adopted by the Board.*

Of these three "prongs" of the BACT definition, the first and third are generally controlling. These two criteria are generally referred to as: (1) achieved in practice, and (2) technologically feasible and cost-effective.

This analysis will follow EPA's guidance for the preparation of "top down" BACT analyses focusing specifically on identifying emission limitations or control techniques that are achieved in practice and technically feasible. Duke Energy is proposing to achieve emission rates for all pollutants that are consistent with the California Air Resources Board's guidance on power plant siting issued in 1999. However, in response to specific requests from the San Luis Obispo County APCD and EPA, this analysis specifically addresses the use of SCONOx to control emissions as an alternative to Selective Catalytic Reduction.

A "top-down" analysis format, consistent with guidance provided in EPA's October 1990 Draft New Source Review Workshop Manual, has been used for the BACT analysis. That guidance lays out five steps for a top-down BACT analysis, as follows:

1. Identify all control technologies
2. Eliminate technically infeasible options
3. Rank remaining control technologies by control effectiveness
4. Evaluate most effective controls and document results
5. Select BACT

This procedure is followed for each of the pollutants evaluated in this analysis.

1. Control of Nitrogen Oxides

a. Identify All Control Technologies

The baseline NOx emission rate for this analysis is considered to be 75 ppmvd @ 15% O_2, based on the governing new source performance standard (40 CFR 60 Subpart GG). This emission rate provides the frame of reference for the evaluation of control effectiveness and feasibility. The maximum degree of control, resulting in the minimum emission rate, is a combination of dry low-NOx combustors and either selective catalytic reduction or SCONOx to achieve a long-term NOx limit of approximately 1 ppmvd. Several intermediate levels of control are also evaluated.

There are three basic means of controlling NOx emissions from combustion turbines: wet combustion controls, dry combustion controls, and post-combustion controls. Wet and dry combustion controls act to reduce the formation of NOx during the combustion process, while post-combustion controls remove NOx from the exhaust stream. Potential NOx control technologies for combustion gas turbines include the following:

Wet combustion controls

- Water injection
- Steam injection

Dry combustion controls

- Dry low-NOx combustor design
- Catalytic combustors (e.g., XONON)
- Other combustion modifications

Post-combustion controls

- Selective non-catalytic reduction (SNCR)

- Non-selective catalytic reduction (NSCR)
- Selective catalytic reduction (SCR)
- SCONOx

b. Eliminate Technically Infeasible Options

The performance and technical feasibility of available NOx control technologies are discussed in more detail below.

(a) Wet Combustion Controls

Steam or water injection directly into the turbine combustor is one of the most common NOx control techniques for combustion turbines. These wet injection techniques lower the flame temperature in the combustor and thereby reduce thermal NOx formation. The water or steam-to-fuel injection ratio is the most significant factor affecting the performance of wet controls. Steam injection techniques can reduce NOx emissions in gas-fired turbines to between 15 and 25 ppmv at 15% O_2; the practical limit of water injection has been demonstrated at approximately 25-42 ppmv @ 15% O_2 before combustor damage becomes significant. Higher diluent:fuel ratios (especially with steam) not only result in greater NOx reductions, but also increase emissions of CO and hydrocarbons, reduce turbine efficiency, and may increase turbine maintenance requirements. The principal NOx control mechanisms are identical for water and steam injection. Water or steam is injected into the primary combustion chamber to act as a heat sink, lowering the peak flame temperature of combustion and thus lowering the quantity of thermal NOx formed. The injected water or steam exits the turbine as part of the exhaust.

Since steam has a higher temperature/enthalpy than water, more steam is required to achieve the same quenching effect. Typical steam injection ratios are 0.5 to 2.0 pounds steam per pound fuel; water injection ratios are generally below 1.0 pound water per pound fuel. Because water has a higher heat absorbing capacity than steam (due to the temperature and to the latent heat of vaporization associated with water), it takes more steam than water to achieve an equivalent level of NOx control.

Although the lower peak flame temperature has a beneficial effect on NOx emissions, it can also reduce combustion efficiency and prevent complete combustion. As a result, CO and VOC emissions increase as water/steam-to-fuel ratios increase. Thus, the higher steam-to-fuel ratio required for NOx control will tend to cause higher CO and VOC emissions from steam-injected turbines than from water-injected turbines, due to the kinetic effect of the water molecules interfering with the combustion process. However, steam injection can reduce the heat rate of the turbine so that equivalent power output can be achieved with reduced fuel consumption and reduced SO_2 emission rates.

Water and steam injection have been in use on both oil- and gas-fired turbines in all size ranges for many years, so these NOx control technologies are clearly technologically feasible and widely available.

(b) Dry Combustion Controls

Combustion modifications that lower NOx emissions without wet injection include lean combustion, reduced combustor residence time, lean premixed combustion, and two-stage rich/lean combustion. Lean combustion uses excess air (greater than stoichiometric air-to-fuel ratio) in the combustor primary combustion zone to cool the flame, thereby reducing the rate of thermal NOx formation. Reduced combustor residence times are achieved by introducing dilution air between the combustor and the turbine sooner than with standard combustors. The combustion gases are at high temperatures for a shorter time, which also has the effect of reducing the rate of thermal NOx formation.

The most advanced combination of combustion controls for NOx is referred to as dry low-NOx (DLN) combustors. DLN technology uses lean, premixed combustion to keep peak combustion temperatures low, thus reducing the formation of thermal NOx. This technology is effective in achieving NOx emission levels comparable to levels achieved using wet injection without the need for large volumes of purified water and without the increases in CO and VOC emissions that result from wet injection. Several turbine vendors have developed this technology for their engines, including the engine proposed for this project. This control technique is technically feasible.

Catalytic combustors use a catalytic reactor bed mounted within the combustor to burn a very lean fuel-air mixture. This technology has been commercially demonstrated under the trade name XONON in a 1.5 MW natural gas-fired turbine in Santa Clara, California, and commercial availability of the technology for a 200 MW GE Frame 7 natural gas-fired turbine was recently announced for one project. (The technology has also been announced as commercially available for some models of small gas turbines, generally 10 MW in size and less.) The combustor used in the Santa Clara demonstration engine is generally comparable in size to that used in GE Frame 7F engines; however, the Frame 7F turbine has many of these combustors, and each is rated at a higher output than the combustor used in the smaller turbine. General Electric has not announced this technology commercially for the engines proposed for the Morro Bay modernization project. Based on discussions with the technology's supplier, Catalytica Corporation, and with the turbine supplier, General Electric, a commercial quotation for the use of XONON in this project is not available for the MBPP. No turbine vendor, other than General Electric, has indicated the commercial availability of catalytic combustion systems at the present time; therefore, catalytic combustion controls are not available for this specific application and are not discussed further.

(c) Post-Combustion Controls

SCR is a post-combustion technique that controls both thermal and fuel NOx emissions by reducing NOx with a reagent (generally ammonia or urea) in the presence of a catalyst to form water and nitrogen. NOx conversion is sensitive to exhaust gas temperature, and performance can be limited by contaminants in the exhaust gas that may mask the catalyst (sulfur compounds, particulates, heavy metals, and silica). SCR is used in numerous gas turbine installations throughout the United States, almost exclusively in conjunction with other wet or dry NOx combustion controls. SCR requires the consumption of a reagent (ammonia or urea) and requires periodic catalyst replacement. Estimated levels of NOx control are in excess of 90%.

Selective non-catalytic reduction (SNCR) involves injection of ammonia or urea with proprietary conditioners into the exhaust gas stream without a catalyst. SNCR technology requires gas temperatures in the range of 1200° to 2000° F and is most commonly used in boilers. The exhaust temperature for the proposed gas turbine ranges from 1087° to 1200° F, which is well below the minimum SNCR operating temperature. Some method of exhaust gas reheat, such as additional fuel combustion, would be required to achieve exhaust temperatures compatible with SNCR operations, and this requirement makes SNCR technologically infeasible for this application. Even when technically feasible, SNCR is unlikely to achieve NOx reductions in excess of 80%-85%.

Nonselective catalytic reduction (NSCR) uses a catalyst without injected reagents to reduce NOx emissions in an exhaust gas stream. NSCR is typically used in automobile exhaust and rich-burn stationary IC engines, and employs a platinum/rhodium catalyst. NSCR is effective only in a stoichiometric or fuel-rich environment where the combustion gas is nearly depleted of oxygen, and this condition does not occur in turbine exhaust where the oxygen concentrations are typically between 14 and 16%. For this reason, NSCR is not technologically feasible for this application.

SCONOx is a proprietary catalytic oxidation and adsorption technology that uses a single catalyst for the control of NOx, CO, and VOC emissions. The catalyst is a monolithic design, made from a ceramic substrate with both a proprietary platinum-based oxidation catalyst and a potassium carbonate adsorption coating. The catalyst simultaneously oxidizes NO to NO_2, CO to CO_2, and VOCs to CO_2 and water, while NO_2 is adsorbed onto the catalyst surface where it is chemically converted to and stored as potassium nitrates and nitrites. The SCONOx potassium carbonate layer has a limited adsorption capability and requires regeneration approximately every 12-15 minutes in normal service.[2] Each regeneration cycle requires approximately 3-5 minutes. At any point in time, approximately 20% of the compartments in a SCONOx system would be in regeneration mode, and the remaining 80% of the compartments would be in oxidation/absorption mode.[3]

Regeneration of the adsorption layer requires exposure of the catalyst to hydrogen gas. In practice, this is accomplished by reforming natural gas with high-pressure steam to produce a gas mixture consisting of methane, carbon dioxide, and hydrogen that is passed over the catalyst beds.[4] Initial attempts by the developer of the process to create regeneration gases from natural gas and steam within the SCONOx catalyst bed (internal autothermal regeneration) failed to produce consistent results; this approach was abandoned in favor of the current offering, which uses an external steam-heated reformer that partially reforms the natural gas to produce the gas mixture that is introduced into the catalyst bed.[5] The reformation reaction continues to some extent within the catalyst bed due to the presence of steam and the temperature of the catalyst surface, but some methane and VOCs from the natural gas remain.

Because the active regenerant gas is hydrogen, the regeneration process must be performed in an atmosphere of low oxygen to prevent dilution of the hydrogen. In practice, the oxygen present in the exhaust gas of combustion turbines is excluded from the catalyst bed by dividing the catalyst bed into a number of individual cells or compartments that are equipped with front and rear dampers that are closed

[2] Personal communication, ABB Environmental, 1/18/00.
[3] Stone & Webster, "Independent Technical Review – SCONOx Technology and Design Review", February 2000.
[4] Stone & Webster, op cit
[5] ABB Environmental, op cit

at the beginning of each regeneration cycle. Proper regeneration of the SCONOx catalyst system depends upon the proper functioning and sealing of these sets of dampers approximately 4 times per hour so that an adequate concentration of hydrogen can be maintained in each module to accomplish complete regeneration of the catalyst before the dampers are opened and the compartment is placed back in service.

Because the SCONOx catalyst can be "poisoned" or rendered inactive by even the very small amounts of sulfur compounds present in natural gas, a SCOSOx catalyst bed (or "guard bed") that is intended to remove trace quantities of sulfur-bearing compounds from the exhaust gas stream is installed upstream of the SCONOx catalyst bed. Like the SCONOx catalyst, the SCOSOx catalyst must be regenerated. Regeneration of the two catalyst types occurs at the same time, with the same regeneration gas supply provided to both; however, the sulfur-bearing regeneration gases for the SCOSOx catalyst exit the SCONOx modules separately from the SCONOx regeneration gases to avoid contaminating the SCONOx catalyst beds. Both regeneration gas streams are returned to the gas turbine exhaust stream downstream of the SCONOx module.[6]

The external reformer used to create the regeneration gases is supplied with steam and natural gas. For one F-class turbine, an estimated 15,000 to 20,000 lbs/hr of 600°F steam is required, along with approximately 100 pounds per hour (2.2 MMbtu/hr) of natural gas.[7] To avoid poisoning the reformer catalyst, the natural gas supplied to the reformer passes through an activated carbon filter to remove some of the sulfur-bearing compounds that are added to natural gas to facilitate leak detection.[8]

To properly treat the CT exhaust gas without undue backpressure, an estimated 40-60 catalyst modules would be required for an F-class machine.[9] The pressure drop associated with a NOx removal efficiency of 90% is approximately 5" of water (in. wg).[10] The estimated space velocity for such a system is 22,000/hour.[11]

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[6] ABB Environmental, op cit
[7] Ibid
[8] Stone & Webster, op cit
[9] ABB Environmental, op cit
[10] Ibid
[11] Ibid

The regeneration cycle time is expected to be controlled using a feedback system based on NOx emission rates.[12] That is, the higher the NOx emissions are relative to the design level, the shorter the absorption cycle, and regeneration cycles will occur more frequently. This is analogous to the use of feedback systems for controlling reagent (ammonia or urea) flow rates in an SCR system.

Maintenance requirements for SCONOx systems are expected to include periodic replacement of the reformer fuel sulfur carbon unit, periodic replacement of the reformer catalyst, periodic washings of the SCOSOx and SCONOx catalyst beds, and periodic replacement of the SCOSOx and SCONOx catalyst beds. The replacement frequency for the reformer sulfur carbon unit and reformer catalyst is unknown to Duke Energy at present. The SCOSOx catalyst is expected to require washing once per year. The lead (upstream) SCONOx catalyst bed is expected to require washing once per year, while the trailing (downstream) SCONOx catalyst bed(s) are expected to require washing once every three years. The annual catalyst washing process is expected to take approximately three days for an F-class machine, at an estimated annual cost of $200,000.[13] The estimated catalyst life is reported to be 7 washings;[14] the guaranteed catalyst life is 3 years.[15]

The adsorption temperature operating range for the SCONOx system is 300°F to 700°F, with an optimal temperature of approximately 600°F.[16] However, regeneration cycles are not initiated unless the catalyst bed temperature is above 450°F to avoid the creation of hydrogen sulfide during the regeneration of the SCOSOx catalyst.[17]

Estimates of control system efficiency vary. ABB Environmental has indicated that the SCONOx system is capable of achieving a 90% reduction in NOx; a 90% reduction in CO, to a level of 2 ppm; and an 80%-85% reduction in VOC emissions.[18] (This VOC reduction is not likely to be achieved with low VOC inlet concentrations, in the 1–2 ppm range.[19]) Commercially quoted NOx emission rates for the SCONOx system range from 2.0 ppm on a 3-hour average basis, representing a 78% reduction,[20] to 1.0 ppm with no

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[12] Ibid
[13] Ibid
[14] Ibid
[15] Letter from ABB Alstom Power to Bibb & Associates dated May 5, 2000. (ABB Three Mountain Power or ABB TMP)
[16] Ibid
[17] ABB Environmental, op cit. Stone & Webster, op cit
[18] ABB Environmental, op cit
[19] Ibid
[20] ABB TMP, op cit

averaging period specified (96% reduction).[21] The SCONOx system does not control or reduce emissions of sulfur oxides or particulate matter from the combustion device.[22]

The SCONOx system has been applied at the Sunlaw Federal Cogeneration Plant in Vernon California since December 1996, and at the Genetics Institute Facility in Massachusetts. The Sunlaw facility uses an LM-2500 gas turbine, rated at a nominal 23 MW, and the Genetics Institute facility has a 5 MW Solar gas turbine.

The SCONOx system was proposed for use by PG&E Generating Company at its La Paloma facility; however, PG&E Generating no longer plans to use the SCONOx system at that site.[23] The SCONOx system is currently proposed for demonstration by PG&E Generating Company at the Otay Mesa Generating Project. In addition, the technology's co-developer, Sunlaw, has proposed to use the technology in conjunction with ABB gas turbines at the Nueva Azalea site in Southern California.

As discussed further below, there are serious questions about the probability of a successful commercial demonstration and the commercial availability of the technology for application to the proposed Morro Bay modernization project, as well as the levels of emission control that can be consistently achieved. However, based on the preceding discussion, the SCONOx system will be considered as technologically feasible for the purposes of this analysis.

Based on the discussions above, the following NOx control technologies are available and potentially technologically feasible for the proposed project:

- Water injection
- Steam injection
- Dry Low-NOx Combustors
- Selective Catalytic Reduction
- SCONOx

[21] Letter from ABB Alstom Power to Sunlaw Energy Corporation dated February 11, 2000. (ABB Sunlaw)
[22] ABB Environmental, op cit
[23] Ibid

c. Rank Remaining Control Technologies by Control Effectiveness

The remaining technically feasible control technologies are ranked by NOx control effectiveness in Table 1.

Table 1
NOx Control Alternatives

NOx Control Alternative	Available?	Technically Feasible?	NOx Emissions (@ 15% O_2)	Environmental Impact	Energy Impacts
Water Injection	Yes	Yes	25-42 ppm	Increased CO/VOC	Decreased Efficiency
Steam Injection	Yes	Yes	15 – 25 ppm	Increased CO/VOC	Increased Efficiency
Dry Low-NOx Combustors	Yes	Yes	9-25 ppm	Reduced CO/VOC	Increased Efficiency
Selective Catalytic Reduction	Yes	Yes	>90% reduction 1 – 2.5 ppm	Ammonia slip	Decreased Efficiency
SCONOx	Yes[1]	Yes[2]	>90% reduction 1 – 2.5 ppm	Reduced CO; potential reduction in VOC	Decreased Efficiency

Notes:
1. There are no standard, commercial guarantees for utility-scale projects for this technology available in the public domain.
2. This technology has been used on small (5 MW and 22 MW) gas turbines for a limited period of time. It has not been used on utility-scale gas turbines.

d. Evaluate Most Effective Controls and Document Results

Water and steam injection are control technologies that, for large gas turbines, have been largely superseded by dry low-NOx combustors, due to the superior emission control performance, additional CO and VOC benefits, and increased efficiency of this technology. Since the Morro Bay project proposes to use dry low-NOx combustors, no further discussion of water injection, steam injection, or dry low-NOx combustors is necessary.

The performance of SCR and SCONOx, insofar as NOx emission levels are concerned, are essentially equivalent. Both technologies have demonstrated the ability to reduce NOx emissions by at least 90%, and differences between low NOx levels (1 ppm vs 2 ppm vs 2.5 ppm) appear, in the case of each technology, to be largely a function of catalyst size, turbine outlet NOx concentration, and compliance terms (e.g., averaging period). The principal differences between the two technologies are associated with whether the low emission levels proposed have been achieved in practice using these technologies, their cost-effectiveness in achieving these levels, and secondary environmental impacts.

Achieved in Practice Evaluation:

The San Luis Obispo County APCD does not have any formal, established criteria for determining when a technology should be considered achieved in practice. The South Coast Air Quality Management District (AQMD) has established more formal criteria for determining when emission control technologies should be considered achieved in practice (AIP) for the purposes of BACT determinations. That District's BACT Scientific Review Committee has recently reviewed a proposed clarification of those criteria. The proposed criteria include the following elements:

<u>Commercial Availability</u>: At least one vendor must offer this equipment for regular or full-scale operation in the United States. A performance warranty or guaranty must be available with the purchase of the control technology, as well as parts and service.

<u>Reliability</u>: All control technologies must have been installed and operated reliably for at least six months. If the operator did not require the basic equipment to operate daily, then the equipment must have at least 183 cumulative days of operation. During this period, the basic equipment must have operated (1) at a minimum of 50% design capacity; or (2) in a manner that is typical of the equipment in order to provide an expectation of continued reliability of the control technology.

<u>Effectiveness</u>: The control technology must be verified to perform effectively over the range of operation expected for that type of equipment. If the control technology will be allowed to operate at lesser effectiveness during certain modes of operation, then those modes of operation must be identified. The verification shall be based on a performance test or tests, when possible, or other performance data.

<u>Technology Transfer</u>: BACT is based on what is AIP for a category or class of source. However, USEPA guidelines require that technology that is determined to be AIP for one category of source be considered for transfer to other source categories. There are two types of potentially transferable

control technologies: (1) exhaust stream controls, and (2) process controls and modifications. For the first type, technology transfer must be considered between source categories that produce similar exhaust streams. For the second type, technology transfer must be considered between source categories with similar processes.

Discussion of SCR-Based Limits – Achieved in Practice Criteria

SCR has been achieved in practice at numerous gas turbine installations throughout the world. Although there are a large number of gas turbines equipped with SCR systems, there are relatively fewer systems in operation that are designed to meet low NOx permit limits of 2.5 ppm or less.

Available CEMS data from the SMUD/SPAC Campbell Soup plant in Sacramento, California, indicate NOx control levels on a continuous basis that are in compliance with a 3.0 ppm limit. Actual NOx levels from that facility, which is equipped with a 120 MW (nominal) Siemens V84.2 turbine, are comfortably below that limit, at approximately 2.5 ppm. This facility has experienced a limited number of events above the permit limit; in each case, the excursion has been associated with a trip of the gas turbine from pre-mix, or low-NOx, mode into diffusion mode. The permit for the facility has since been modified to accommodate up to ten hours per year of excursions above the 3 ppm permit limit under specified conditions.

The extrapolation of SCR experience gained at higher NOx concentrations (3-5 ppm), where there are more sites in operation, to lower NOx permit limits depends on controlling turbine exhaust (SCR inlet) NOx concentrations, increasing catalyst size, improving feed-forward and feed-back control system design to ensure better process control, and ensuring good distribution of reagent to match the distribution of NOx levels. The experience at the SMUD/SPAC site, however, indicates that the ability of the SCR system to track NOx emissions changes upstream of the catalyst is further challenged at progressively lower concentrations.

A further exacerbating factor is related to measurement uncertainty. The South Coast AQMD has indicated that current NOx measurement methods for stationary sources are accurate to ±1 ppm,[24] which becomes problematic at NOx permit levels of 5 ppm and lower.

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[24] See, e.g., South Coast AQMD Protocol for Rule 2012

The following paragraphs evaluate the proposed AIP criteria as applied to the achievement of extremely low NOx levels (2.5 ppm and lower) using SCR technology.

Commercial availability: SCR technology is available with standard commercial guarantees for NOx levels at least as low as 1 ppm. Consequently, this criterion is satisfied.

Reliability: SCR technology has been shown to be capable of achieving NOx levels consistent with a 3 ppm permit limit during extended, routine operations of the SMUD/SPAC facility. There are no reported adverse effects of operation of the SCR system at these levels on overall plant operation or reliability.

Effectiveness: SCR technology has been demonstrated to achieve NOx levels below 3 ppm. At the SMUD/SPAC site, short-term excursions have resulted in NOx concentrations above 3 ppm; however, these excursions have not been associated with diminished effectiveness of the SCR system. Rather, these excursions have been associated with SCR inlet NOx levels in excess of those for which the SCR system was designed. As a consequence, the application of SCR technology to achieve extremely low NOx levels should reflect the potential for infrequent NOx excursions, under specified conditions.

Conclusion: SCR technology capable of achieving NOx levels below 3 ppm is considered to be achieved in practice. The current BACT guidelines used by the CARB and EPA indicate that NOx levels of 2.5 ppm on a 1-hour average basis, or 2.0 ppm on a 3-hour average basis, should be considered BACT for utility-scale gas turbines. This analysis is consistent with those guidelines. The achievement of NOx concentrations below these levels, on either a short term or long term basis, is not demonstrated in practice.

Discussion of SCONOx-Based Limits – Achieved in Practice Criteria

SCONOx has been demonstrated in service in two applications: The Federal Cogeneration Facility in Vernon, California, and the Genetics Institute Facility in Massachusetts. Because these turbines are much smaller than those proposed for the Morro Bay modernization project, issues related to the application of SCONOx technology to Morro Bay need to be evaluated, in addition to a review of other criteria.

Available CEMS data from the Federal Vernon facility have been obtained from EPA, covering the period July through December 1997. EPA has indicated that this time period reflected the improved performance of the SCONOx system, and led to EPA's March 23, 1998 letter regarding BACT and LAER requirements for combined cycle gas turbines.

A review of the available SCONOx data for the last half of 1997 indicates that, at the Federal site, up to 12 exceedances per year could be expected above a 3.0 ppm, 3-hour average limit, even when exceedances related to startups and shutdowns were excluded.

EPA and ARB have recommended BACT/LAER levels for combined cycle gas turbines of either 2.0 ppm on a 3-hour average basis, or 2.5 ppm on a 1-hour average basis. Under the BACT/LAER levels recommended by these agencies, the 1997 SCONOx data from the Federal site indicate that a 3-hour average limit of 2.0 ppm would be exceeded 44 times per year, and a 1-hour average limit of 2.5 ppm would be exceeded 24 times per year. Again, these data exclude exceedances associated with startups and shutdowns, as described above.

The data supporting these conclusions are shown in Table 2.

The first part of this table shows, by month and quarter, the number of all 1-hour and 3-hour exceedances of various NOx emissions levels associated with operation of the SCONOx system during the period that resulted in EPA's March 1998 letter. The second part of the table shows exceedances that were not due to turbine startups or shutdowns.

Table 2

SCONOx Performance – Summary Prepared by Sierra Research

July 1, 1997 to December 31, 1997

SCONOx Excursions Review

All excursions:

Month	No. of Valid CEMS Hrs	CEMS Avail, %	No. of 1-hr periods exceeding 2.0 ppmc	2.5 ppmc	3.0 ppmc	No. of 3-hr periods exceeding 2.0 ppmc	2.5 ppmc	3.0 ppmc	Highest reading 1-hr avg	3-hr avg
Jul	739.00	99.33	3	3	2	1	0	0	4.2	2.3
Aug	741.00	99.60	4	3	2	5	0	0	4.4	2.2
Sept	715.00	99.31	3	2	2	3	2	2	5.0	3.7
Quarter	**2195.00**	**99.41**	**10**	**8**	**6**	**9**	**2**	**2**	**5.0**	**3.7**
Oct	731.00	98.25	9	5	5	10	9	8	10.9	7.5
Nov	716.00	99.44	18	16	14	29	19	14	9.6	6.3
Dec	723.00	97.18	6	4	2	7	4	1	5.4	3.2
Quarter	**2170.00**	**98.28**	**33**	**25**	**21**	**46**	**32**	**23**	**10.9**	**7.5**

Excursions not due to startups or shutdowns:

Month	No. of Valid CEMS Hrs	CEMS Avail, %	No. of 1-hr periods exceeding 2.0 ppmc	2.5 ppmc	3.0 ppmc	No. of 3-hr periods exceeding 2.0 ppmc	2.5 ppmc	3.0 ppmc	Highest reading 1-hr avg	3-hr avg
Jul	739.00	99.33	1	1	0	0	0	0	2.6	1.8
Aug	741.00	99.60	3	2	1	4	0	0	3.5	2.2
Sept	715.00	99.31	1	0	0	0	0	0	2.2	2.0
Quarter	**2195.00**	**99.41**	**5**	**3**	**1**	**4**	**0**	**0**	**3.5**	**2.2**
Oct	731.00	98.25	5	3	3	5	5	5	10.9	7.5
Nov	716.00	99.44	5	4	3	8	2	1	8.6	3.8
Dec	723.00	97.18	4	2	1	5	2	0	4.0	2.8
Quarter	**2170.00**	**98.28**	**14**	**9**	**7**	**18**	**9**	**6**	**10.9**	**7.5**

Note: All NOx readings corrected to 15% oxygen.

In this analysis, no more than 2 hours of NOx emissions following a startup were treated as part of the startup. For the 3-hour averages, any average that included a startup hour was attributed to the startup. This is in contrast with the approach taken by Goal Line Environmental Technologies (GLET) in its comments accompanying the data reports, in which it is clear that startup periods were considered to extend as much as 6 hours. (This is particularly inappropriate for aeroderivative turbines such as those used at the Federal facility, which are known for their ability to start within tenths of minutes.) NOx emissions greater than 2 ppm occurring during these long startup periods were reported by GLET, but were not considered to be exceedances. In summary, using a 2-hour startup period for aeroderivative gas turbines, the data reported by GLET to EPA for 1997 do not support a BACT determination below 3 ppm. Based solely on the SCONOx data presented to EPA, even a NOx limit at 3.0 ppm would have to provide for excursions, other than startups and shutdowns, above that limit. The number of excursions needed would depend upon the NOx limit selected and the emission control technology employed.

Additional data have been generated at the Federal site, and were provided to EPA Region IX by CURE.[25] These data were for

April 1, 1999 to December 31, 1999

Plant Statistics

Total Hours in Review Period	6,400	
Number of Operating Hours	2,583	
Number of Turbine Starts	149	
Number of CEM Data Periods with Turbine Operating	10,331	
Number of negative CEM values		
NOx:	0	0%
CO:	6,494	63%

Valid Data Periods (Excludes Startup/Shutdown, CEM Maintenance)

NOx Limit (ppm) -> Averaging Period	3.0	2.5	2.0	1.5	1.3
15 min	9,861	9,813	9,742	9,649	9,607
1 hour	2,501	2,491	2,470	2,445	2,434
3 hour	2,498	2,488	2,468	2,445	2,434

Exceedance Periods (Excludes Startup/Shutdown, CEM Maintenance)

NOx Limit (ppm) -> Averaging Period	3.0	2.5	2.0	1.5	1.3
15 min	71	77	92	111	124
1 hour	18	21	24	29	32
3 hour	20	22	26	32	36

the period April 1, 1999 through December 31, 1999, and were provided to Sierra Research by EPA Region IX.[26] The more recent data are consistent with the earlier data, and are summarized in Table 3.

The 1999 CEMS data from the Federal facility indicated that the turbine equipped with SCONOx was operated fewer than 2,600 hours during the nine-month period for which data were provided. During this period, the turbine was started 149 times. The CEMS data for CO, in particular, are suspect; more than 60% of the CO values reported were less than zero, indicating that the CO analyzer was not properly calibrated on a daily basis. For this reason, the CO data for this period were not analyzed further.

The NOx emissions data for this period were analyzed to evaluate compliance with five hypothetical emission limits (3.0, 2.5, 2.0, 1.5, and 1.3 ppm) and three compliance averaging periods (15 minute, 1 hour, 3 hour). Valid data periods were considered to be those that excluded startups, shutdowns, and documented CEMS maintenance. Startups were defined to be periods commencing with the initiation of fuel flow to the engine, and lasting until the NOx emission limit under evaluation was met, but not exceeding a period of two hours. Shutdown periods were defined to be periods ending with the cessation of

Table 3

[25] Letter dated March 14, 2000, from Katherine Poole, Adams Broadwell Joseph & Cardozo, to Steve Branoff, EPA Region IX.

[26] Letter dated June 28, 2000 from Duong Nguyen, EPA Region IX, to Nancy Matthews, Sierra Research.

fuel flow to the engine and starting when the NOx emission limit under evaluation was no longer met, but not exceeding a period of 30 minutes. A valid 1-hour average period was defined to require at least two valid 15-minute periods; a valid 3-hour average period was defined to require at least two valid 1-hour average periods. All of the above definitions are typical for utility-scale gas turbine CEMS systems.

The data indicated that there were 9,600 to 9,900 valid 15-minute periods, excluding startups, shutdowns, and CEMS maintenance, depending on the NOx limit being evaluated. There were numerous exceedances of the hypothetical NOx limits during these periods, ranging from 71 periods in which NOx emissions exceeded 3.0 ppm to 124 periods in which NOx emissions exceeded 1.3 ppm.

There were approximately 2,500 valid 1-hour average periods in the data set, excluding startups, shutdowns, and CEMS maintenance. For 1-hour average limits, the data again showed numerous exceedances, ranging from 18 exceedances of a 3.0 ppm NOx limit to 32 exceedances of a 1.3 ppm limit. Finally, during the approximately 2,500 valid 3-hour average periods in the data set, there were 20 exceedances of a 3.0 ppm limit and 36 exceedances of a 1.3 ppm NOx limit.

In summary, the more recent data fail to support the conclusion that the SCONOx system at the Federal facility is capable of consistently maintaining low NOx levels of 3.0 ppm or less. Depending on the NOx limit evaluated, the periods of non-compliance over a nine-month period ranged from 18 to 32 hours, excluding periods of turbine startup, shutdown, and CEMS maintenance. While each of the exceedances was accompanied in the data file with an explanation, these explanations do not eliminate the exceedances. In fact, of the 24 exceedances of a 3.0 ppm NOx limit on a 1-hour average basis observed in the 1999 data, 14 were explicitly attributed to problems with the SCONOx system in the file presenting the CEMS data.

Table 4 compares the results of the analyses of the 1997 and 1999 data, with both data sets normalized to predict exceedances over a 12-month period.

The more recent data do not indicate improved performance as compared with the 1997 CEMS data.

Table 4

Comparison of 1997 and 1999 SCONOx CEMS Data
Exceedances of Hypothetical Permit Limits – Annualized Basis
(Excluding startups/shutdowns/CEMS maintenance)

Data Set	1-hour average			3-hour average		
	3.0 ppm limit	2.5 ppm limit	2.0 ppm limit	3.0 ppm limit	2.5 ppm limit	2.0 ppm limit
1997	16	24	38	12	18	44
1999	24	28	32	26	29	34

In addition to performance-related issues regarding SCONOx, there are concerns regarding the demonstration of durability of the regeneration gas and damper/sealing systems, and the ability of the SCONOx system to respond to transient conditions that result in changes in turbine-exhaust NOx levels.

With respect to the damper/sealing system, there have been three different designs discussed in technical literature regarding SCONOx. Table 5 summarizes these designs.

Stone and Webster reported that the initial operation of the SCONOx system at the Genetics Institute facility resulted in a rapid loss of performance due to a lack of regeneration. This problem was traced to mechanical deficiencies, including seal and gasket leakage. Corrective actions taken included replacement of the flexible metal damper seals with tadpole seals, installation of a manual throttling valve in the gas return line, re-gasketing and re-sealing of the heat exchanger flanges, and adjustment of the damper actuators. Further changes to the overall system included adding an external reformer, adding a sulfur filter to remove sulfur from the gas that feeds the external reformer, and modifying the damper/seal system.

Although the damper/sealing system was subjected to a 101,000 cycle test (equivalent to approximately 25,000 operating hours based on 15-minute cycle times), Stone & Webster reported that a number of damper/seal design changes have been proposed by ABB based on those test results. These changes include a modification to the tadpole design to avoid excessive stress at the location where the damper blade rests on the seal, and modifications to the shaft design to preclude leaks associated with fabric failure near the shaft-seal interface.

As of the date of their report (February 22, 2000), Stone & Webster indicated that full-scale testing of the new seal design had not been performed. In particular, Stone & Webster noted that "the use of fiberglass in the temperature range of 600°F to 700°F with frequent flexing and relaxing, over the expected design period of three years, is yet to be demonstrated."

Based on this information, the following paragraphs evaluate the proposed AIP criteria as applied to the achievement of extremely low NOx levels (2.5 ppm and lower) using SCONOx technology.

Commercial availability: It is not clear whether SCONOx technology is presently available with standard commercial guarantees for NOx levels at least as low as 2.5 ppm. A request for a copy of the guarantee for SCONOx performance from the developers of the Otay Mesa Generating Project was rejected. An excerpt of the guarantee from the system vendor to Sunlaw Energy, a co-developer of the SCONOx system, was included as an appendix to the Application for Certification for the Nueva Azalea project. However, this guarantee is between two parties with

Table 5
Summary of SCONOx Installations

	Federal Cogeneration[1]	Genetics Institute[1]	Proposed Future (F-class turbine)
Regeneration Gas System			
Regeneration system type	Direct hydrogen injection	External reformer	External reformer
Regen Gas Flow Rate	1520 acfm	1050 acfm	
SCOSOx (Guard Bed) Catalyst System			
Cell Density	Not installed (periodic water washing of catalyst is performed instead)		
Substrate			
Catalyst Volume		26.25 cu ft	
Space Velocity - Absorption - Regeneration	 	 116,630 6,000	 114,000 4,000
Cycle Times - Absorption - Regeneration		 12 min 3 min	
SCONOx Catalyst System			
Cell Density	230	230	
Substrate	Ceramic	Ceramic	
Catalyst Volume	294 cu ft	157.5 cu ft	
Space Velocity - Absorption - Regeneration	 11,100 275	 19,440 1,000	 22,000 750
Cycle Times - Absorption - Regeneration	 12 min 4 min	 12 min 3 min	
Damper/Seal Systems			
Number of Modules	4	5	40-60[2]
Number of Dampers	12	10	80-120[2]
Damper Type	Louver, flap type	Louver, flap type	Louver, flap type
Damper Support	End supported	Center supported	Center supported
Misc			
Seal Material/Type	316 SS, 'S' type	Fiberglass/stainless steel wool tadpole design	
Actuator Type	Electrical	Electrical	

Notes:
1. Stone & Webster, op cit
2. Modules are joined, four together, to form linked "shelves."

a common financial interest in the demonstration and sale of the SCONOx system, and thus is not necessarily representative of a standard commercial guarantee. Public statements by ABB Environmental, the exclusive licensee of the SCONOx system for gas turbines with a capacity greater than 100 MW, indicate that standard commercial performance guarantees will be provided for this system upon request. It is unclear, however, whether this guarantee will be passed on by the HRSG vendors and/or EPC contractors, as is standard in the industry. In fact, a potential supplier of an HRSG system for the Morro Bay modernization project has indicated, in writing, that the supplier would not back up ABB's performance guarantees or warranty claims because the supplier was "not comfortable with the scale up from the existing size of the current technology."[27] Thus, it is possible that this criterion is satisfied but, as yet, there is no publicly available documentation to support such a conclusion. The only publicly available documentation indicates that SCONOx is not commercially available with standard commercial performance guarantees.

Reliability: To date, there have been no unqualified demonstrations of the ability of the SCONOx system to meet NOx levels of 3 ppm or lower over extended periods of time. The demonstrations at the Federal Cogeneration facility have indicated numerous circumstances under which a 3 ppm level would be exceeded (excluding startup and shutdown conditions), with data from as recently as 1999 having been evaluated. Furthermore, the SCONOx system at the Federal facility uses a different scheme for catalyst regeneration, sulfur protection, and dampers/sealing than that proposed for use in a full-scale, commercial project. The catalyst regeneration system used at the Federal facility involved direct hydrogen injection to the catalyst bed; this system appears to have been rejected for use by ABB Environmental for larger, utility-scale applications. The current sulfur protection system for the SCONOx catalyst-the SCOSOx guard bed system-was not used at the Federal facility, and the sulfur protection system used at the Federal facility (periodic water washing of catalyst elements) appears to have been rejected by ABB Environmental for larger, utility-scale applications. Finally, the end-supported damper system with metal seals used at the Federal facility appears to have been rejected by ABB Environmental for larger, utility-scale applications. Consequently, the Federal facility is not indicative of the reliability of the SCONOx system for utility-scale applications.

The SCONOx installation at the Genetics Institute facility currently uses the new designs for catalyst regeneration, sulfur protection, and dampers/sealing. However, problems associated with that facility's ability to consistently meet NOx levels lower than 3 ppm were reported as recently as February 2000. Although some of those problems were attributed to fluctuations in turbine NOx emissions, rather than problems with SCONOx catalyst efficiency, the Genetics Institute facility does not yet constitute a demonstration that the SCONOx system can reliably meet NOx levels of less than 3 ppm.

Furthermore, the revised damper/seal system in use at the Genetics Institute facility has not been fully tested in field service, as noted by Stone & Webster. The next-prior version of the damper/seal system, which was tested for ABB Environmental in a test facility, exhibited failures of various kinds after approximately 60,000 cycles. Improvements to the damper/seal system to address those failures have not been similarly tested (or, at least, the reports of any such tests have not been presented publicly). Since an F-class gas turbine is expected to require the use of 40-60 modules, with 40-60 pairs of dampers/seals, 40-60 shaft actuators, and approximately 2.7 million damper-cycles per turbine per year,[28] it is unclear that the performance tests conducted to date demonstrate the ability of this portion of the system to ensure compliance with sub-3 ppm NOx levels on a continuous basis.

Effectiveness: As discussed above, the Federal facility uses different catalyst regeneration, sulfur protection, and sealer/damper systems than those being offered by ABB Environmental. Thus, it is not clear that the Federal installation can be used to demonstrate the effectiveness of the systems being proposed for larger, utility-scale projects. The SCONOx

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[27] Telefax message dated June 15, 2000 from Aalborg Industries to Duke/Fluor-Daniel.

[28] Calculated as 40 pairs of dampers per turbine, 2 dampers per pair, 4 cycles per damper per hour, 8400 operating hours per year: 40 x 2 x 4 x 8400 = 2,688,000 damper cycles per year per turbine.

configuration at the Genetics Institute facility is more similar to that proposed for larger turbines; however, that facility "has met or exceeded the performance requirement of 2.5 ppm [NOx] for approximately 330 hours, out of the total hours of operation of approximately 410 hours for which valid data is available."[29] This means that the 2.5 ppm NOx performance target was not met during approximately 20% of the hours within this period. As noted above, many of the exceedances of the 2.5 ppm NOx level at the Genetics Institute site were attributable to operation of the gas turbine's transient pilot. Nonetheless, the available data from that site are not sufficient to conclude that NOx levels of 3 ppm or less can be achieved using the SCONOx system on a consistent basis, nor are the available data from the Federal site suitable for reaching such a conclusion. At a minimum, if SCONOx technology were used to achieve extremely low NOx levels, permit conditions would need to reflect the potential for frequent NOx excursions under specified conditions.

Conclusion: SCONOx technology has been found to be capable of achieving NOx levels below 2.5 ppm by the South Coast AQMD and EPA. However, the presently available technical information does not support a conclusion that this technology is achieved in practice based on South Coast AQMD guidelines.

e. Select BACT

Based on the above analysis, both SCR and SCONOx-based systems are generally considered to be technologically capable of achieving NOx levels below 2.5 ppm, given appropriate consideration to turbine outlet NOx levels, catalyst volume (space velocity), and control system design. For both types of systems, some provision will be necessary to accommodate short-term excursions above permit limits, and for both types of systems, particular attention to CEMS design will be necessary to ensure that low permit limits can be monitored on a continuous and accurate basis.

Based on this information, BACT for NOx is considered to be the use of either SCR or SCONOx systems to achieve NOx levels not higher than 2.5 ppm on a 1-hour average basis, or 2.0 ppm on a 3-hour average basis. Duke Energy proposes to use SCR technology to meet a NOx level of 2.5 ppm on a 1-hour average basis, and the equivalent of 2.0 ppm on an annual average basis. Consequently, Duke's proposal is consistent with BACT requirements for NOx.

2. Control of Ammonia Emissions

The following section discusses alternative control techniques for ammonia emissions.

a. Identify All Control Technologies

Ammonia emissions result from the use of ammonia-based NOx control technologies. There are three basic means of controlling NOx emissions from combustion turbines: wet combustion controls, dry combustion controls, and post-combustion controls. Wet and dry combustion controls act to reduce the formation of NOx during the combustion process, while post-

[29] Stone & Webster, op cit

combustion controls remove NOx from the exhaust stream. Potential NOx control technologies for combustion gas turbines include the following:

Wet combustion controls

- Water injection
- Steam injection

Dry combustion controls

- Dry low-NOx combustor design
- Catalytic combustors (e.g., XONON)
- Other combustion modifications

Post-combustion controls

- Selective non-catalytic reduction (SNCR)
- Non-selective catalytic reduction (NSCR)
- Selective catalytic reduction (SCR)
- SCONOx

Of these NOx control technologies, only two result in ammonia emissions: selective non-catalytic reduction, and selective catalytic reduction.

b. Eliminate Technically Infeasible Options

The performance and technical feasibility of available NOx control technologies were discussed above. Based on the discussions above, the following NOx control technologies are available and potentially technologically feasible for the proposed project:

- Water injection (no ammonia emissions)
- Steam injection (no ammonia emissions)
- Dry Low-NOx Combustors (no ammonia emissions)
- Selective Catalytic Reduction (some ammonia emissions)
- SCONOx (no ammonia emissions)

c. Rank Remaining Control Technologies by Control Effectiveness

The remaining technically feasible control technologies are ranked by ammonia emission rate in Table 6.

Table 6
Ammonia Control Alternatives

Ammonia Control Alternative	Available?	Technically Feasible?	Ammonia Emissions (@ 15% O_2)	Environmental Impact	Energy Impacts
Water Injection	Yes	Yes	0 ppm	Increased CO/VOC	Decreased Efficiency
Steam Injection	Yes	Yes	0 ppm	Increased CO/VOC	Increased Efficiency
Dry Low-NOx Combustors	Yes	Yes	0 ppm	Reduced CO/VOC	Increased Efficiency
Selective Catalytic Reduction	Yes	Yes	2-10 ppm	Ammonia slip	Decreased Efficiency
SCONOx	Yes[1]	Yes[2]	0 ppm	Reduced CO; potential reduction in VOC	Decreased Efficiency

Notes:
1. The availability of standard, commercial guarantees for utility-scale projects is unclear at this time.
2. Technology has been demonstrated on small (5 MW and 22 MW) gas turbines for a limited period of time. No demonstration on utility-scale gas turbines.

d. Evaluate Most Effective Controls and Document Results

Water and steam injection are control technologies that, for large gas turbines, have been largely superseded by dry low-NOx combustors, due to the superior emission control performance, additional CO and VOC benefits, and increased efficiency of this technology. Since the project proposes to use dry low NOx combustors, no further discussion of water injection, steam injection, or dry low NOx combustors is necessary.

The performance of SCR and SCONOx, insofar as NOx emission levels are concerned, has been discussed above. SCONOx results in no emissions of ammonia, while SCR results in ammonia slip levels of up to 10 ppm. The following discussion evaluates potential ammonia slip limits of 10 ppm, 5 ppm, 2 ppm, and 0 ppm. The last limit would be achievable, at the present time, only through the use of SCONOx technology.

Achieved in Practice Evaluation:

This portion of the analysis is performed based on the proposed Achieved in Practice criteria under consideration in the South Coast AQMD. These criteria were discussed above.

Discussion of 10 ppm Ammonia Slip Limit – Achieved in Practice Criteria

SCR has been installed and operated at numerous gas turbine installations throughout the world. Although there are a large number of gas turbines equipped with SCR systems, there are relatively few operating systems designed to meet low NOx permit limits of 3.0 ppm or less. Ammonia slip associated with SCR system operation results from a gradual decline in catalyst activity over time, necessitating the use of increasing amounts of ammonia injection to maintain NOx concentrations at or below the design rate.

The parameters of NOx concentration, ammonia slip limit, and catalyst life are integrally related. That is, catalyst performance is generally specified as being a particular NOx concentration (e.g., 2.5 ppm), guaranteed for N years (e.g., 3 years), with a maximum ammonia slip level of X ppm (e.g., 5 ppm). Such a specification indicates that catalyst performance will degrade over time such that at the end of three years, ammonia slip will increase to not more than 5 ppm while maintaining NOx concentrations at or below 2.5 ppm. During the early period of performance, ammonia slip from an oxidation catalyst is typically less than 1-2 ppm, and will approach the guarantee level only towards the end of the catalyst life.

Early SCR installations, as well as some later installations, have been associated with ammonia slip levels of 10 ppm. In August 1999, the California Air Resources Board adopted a BACT guideline for large gas turbines that proposed to limit ammonia slip to not more than 5 ppm. Since the 5 ppm ammonia slip level is proposed for the Morro Bay modernization project, no further discussion of the 10 ppm and 5 ppm slip levels is required.

Ammonia slip levels of 2 ppm have been required in several permits issued in the eastern United States. However, these permits have typically been associated with higher NOx levels than are proposed here. In particular, 2 ppm ammonia slip limits have been proposed in conjunction with NOx levels that range between 2.0 and 3.5 ppm, depending on operating mode. Although Duke Energy is proposing a 1-hour average NOx limit of 2.5 ppm, the facility is also proposing an annual average NOx limit based on 2.0 ppm. As noted above, the SCR parameters related to NOx limits, ammonia slip, and catalyst life are all integrally related. There are a very few projects that have proposed emission limits of 2 ppm ammonia slip in conjunction with a long-term NOx average of 2.0 ppm; however, none are in operation.

Finally, SCONOx has the potential to achieve this low a NOx level without any ammonia slip.

Consequently, the following discussion compares the use of SCR with a 5 ppm ammonia slip level with SCONOx to meet comparable NOx levels, but without any ammonia slip.

The following paragraphs evaluate the proposed AIP criteria as applied to the achievement of 5 ppm ammonia slip in conjunction with a NOx emission limit of 2.0 ppm on an annual average basis, using SCR technology.

Commercial availability: SCR technology is available with standard commercial guarantees with ammonia slip levels of 5 ppm and 2 ppm, in conjunction with NOx levels at least as low as 2 ppm.

Reliability: SCR technology has been shown to be capable of achieving ammonia slip levels below 5 ppm over at least a three-year catalyst life period. There are no reported adverse effects of operation of the SCR system at these levels on overall plant operation or reliability.

Effectiveness: SCR technology has been demonstrated to achieve ammonia slip levels of less than 5 ppm in conjunction with NOx levels below 3 ppm.

Conclusion: SCR technology capable of achieving ammonia slip levels at or below 5 ppm, in conjunction with NOx levels below 3 ppm, is considered to be achieved in practice. The South Coast AQMD's web site lists three SCR-based BACT determinations for ammonia slip.

The earliest SCR-based BACT determination for ammonia slip listed on the South Coast AQMD's web site is for the Sutter Power Project, which was approved by the Feather River AQMD in April 1999. This project is required to meet an ammonia slip limit of 10 ppm on a 3-hour average basis, in conjunction with a 2.5 ppm NOx limit on a 1-hour average basis.

The next SCR-based BACT determination for ammonia slip listed on the South Coast AQMD's web site is for the La Paloma Generating project, which was approved by the San Joaquin Unified APCD in October 1999. This project is required to meet a 10 ppm ammonia slip limit on a 24-hour average basis in conjunction with a 2.5 ppm NOx limit on a 1-hour average basis.

The third SCR-based BACT determination for ammonia slip listed on the South Coast AQMD's web site is for the Sithe Energy Mystic facility, which was approved by the Massachusetts Department of Environmental Protection (Mass DEP) in January 2000. This project is required to comply with a 2 ppm ammonia slip limit on a 1-hour average basis in conjunction with a 2 ppm NOx limit, 1-hour average basis. The Sithe Mystic facility is also required to evaluate the availability, reliability, and cost of technologies that eliminate ammonia slip emissions, in accordance with the terms of a Memorandum of Understanding between the project operator and Mass DEP.

These permits indicate that, as recently as one year ago, ammonia slip limits of 10 ppm were considered best available control technology. The rapid changes during the last year are indicative of increasing confidence of SCR system vendors in sustaining low ammonia slip rates in conjunction with low NOx emission rates. However, given the lack of any real-world demonstration of these low NOx and ammonia slip levels at the present time, BACT for ammonia slip using SCR-based controls is considered to be 5 ppm for this project.

Discussion of SCONOx-Based Limits – Achieved in Practice Criteria

Based on the discussion presented in the NOx BACT section regarding SCONOx technology, the presently available technical information does not support a conclusion that this technology is achieved in practice based on South Coast AQMD guidelines, when the objective is meeting low NOx levels (below 3 ppm) in combination with low (or zero) ammonia slip.

e. Select BACT

Based on the above analysis, SCR systems capable of achieving ammonia slip limits of 2 ppm and 5 ppm in conjunction with NOx limits of 2 ppm or 2.5 ppm appear to be commercially available, but have not yet been demonstrated in practice. Consequently, since Duke Energy has proposed to achieve an ammonia slip limit of 5 ppm, this value would constitute BACT if an SCR-based control system is selected.

Although SCONOx technology to eliminate ammonia slip is not considered to be achieved in practice, it may be technologically feasible. Therefore, a further evaluation of the cost-effectiveness of this technology was performed. In this analysis, the cost of a SCONOx system was compared with the cost of an SCR system, with the incremental cost assigned to the benefit of eliminating ammonia slip.

It is appropriate to make such an assignment because the performance of the SCR system proposed for the Morro Bay modernization project is comparable to that proposed for SCONOx with respect to NOx emission levels for this project. VOC emissions are expected to be at or below the limits of detection with or without the SCONOx system, and thus no incremental VOC benefits can be ascribed to this technology in this analysis. Proposed CO limits are consistent the state Air Resources Board's BACT guideline, and therefore no incremental benefit for CO reduction is ascribed to the SCONOx system.

With respect to ammonia emissions, the use of SCONOx is assumed to eliminate all ammonia emissions. For the Morro Bay modernization project, this is a reduction of 240.4 tons per year.

The San Luis Obispo County APCD does not have a cost-effectiveness threshold for ammonia or for particulate matter. Since the objective of reducing ammonia emissions is to avoid downwind formation of PM_{10}, the PM_{10} cost-effectiveness thresholds were reviewed to evaluate for ammonia emission reductions. For PM_{10}, the San Joaquin Valley Unified APCD's cost-effectiveness threshold of $5,700 per ton is used, which is higher than the $5,300 per ton value used by the Bay Area AQMD.

Based on these criteria, SCONOx would be cost/effective for the reduction of ammonia and emissions if the annual incremental cost for the Morro Bay modernization project (total for all four turbines), as compared with SCR, is not more than $1.4 million per year. The calculation is as follows:

240.4 tpy * $5700/ton = $1,370,280 / year

As shown in Tables 7A through 7C, the annual incremental cost of SCONOx is $2.6 million per year per turbine, or over $10 million per year for the Morro Bay modernization project. Consequently, SCONOx is not cost/effective as compared with SCR.

Based on the above information, BACT for ammonia is considered to be an ammonia slip limit of 5 ppm.

Duke Energy is proposing to use SCR technology to meet an ammonia slip limit of 5 ppm in conjunction with NOx levels of 2.5 ppm on a 1-hour average basis and 2.0 ppm on an annual average basis. Consequently, Duke Energy's proposal is consistent with the District's BACT requirements.

Table 7A

SCR Costs (per gas turbine/HRSG)

Description of Cost	Cost Factor	Cost ($)	Notes
Direct Capital Costs (DC):			
Purchased Equip. Cost (PE):			
Basic Equipment:			
Auxiliary Equipment: HRSG tube/fin modifications			
Instrumentation: SCR controls			
Ammonia storage system:			
Taxes and freight:			
PE Total:		$1,581,200	1
Direct Install. Costs (DI):			
Foundation & supports:		$0	
Handling and erection:		$0	
Electrical:		$0	
Piping:		$0	
Insulation:		$0	
Painting:		$0	
DI Total:		$395,300	1
Site preparation for ammonia tanks (included in PE cost)		$0	1
DC Total (PE+DI):		$1,976,500	
Indirect Costs (IC):			
Engineering:	0.10 PE	$158,120	2
Construction and field expenses:	0.05 PE	$79,060	2
Contractor fees:	0.10 PE	$158,120	2
Start-up:	0.02 PE	$31,624	2
Performance testing:	0.01 PE	$15,812	2
Contingencies:	0.05 PE	$79,060	1
IC Total:		$521,796	
Less: Capital cost of initial catalyst charge		-$752,000	
Total Capital Investment (TCI = DC + IC):		$1,746,296	
Direct Annual Costs (DAC): 0.5 hr/SCR per shift	hr/yr: 4,380		
Operating Costs (O): sched. (hr/day): 24	day/week: 7 wk/yr: 52		
Operator: hr/shift: 2.0	operator pay ($/hr): 39.20	$85,613	2
Supervisor: 15% of operator		$12,842	2
Maintenance Costs (M): 0.5 hr/SCR per shift			
Labor: hr/shift: 2.0	labor pay ($/hr): 39.2	$85,613	2
Material: % of labor cost: 100%		$85,613	2
Utility Costs:			
Perf. loss: (kwh/unit): 0.0	SCONOx losses are shown as incremental to SCR losses		1
Electricity cost ($/kwh):		$0	
Ammonia based on 120.7 lbs/hr of 28% wt aqueous ammonia, $440/ton		$232,613	4
Catalyst replace: based on 3 year catalyst life		$250,667	1
Catalyst dispose: based on 2,750 ft^3 catalyst, $15/$ft^3$, 3 yr. Life		$13,750	1
Total DAC:		$766,710	
Indirect Annual Costs (IAC):			
Overhead: 60% of O&M		$161,808	2
Administrative:	0.02 TCI	$34,926	2
Insurance:	0.01 TCI	$17,463	2
Property tax:	0.01 TCI	$17,463	2
Total IAC:		$231,660	
Total Annual Cost (DAC + IAC):		$998,370	
Capital Recovery (CR):			
Capital recovery: interest rate (%): 10			
period (years): 15	0.1315	$229,592	2
Total Annualized Costs		$1,227,962	

Table 7B

SCONOx Cost and Incremental Cost (per gas turbine/HRSG)			Notes
Direct Capital Costs			
	Capital (less cost of initial catalyst charge)	$6,900,000	3, 5
	Installation	$0	3
Indirect Capital Costs			
	Engineering	$0	3
	Contingency	$0	3
	Other	-	
Total Capital Investment		$6,900,000	
Direct Annual Costs			
	Maintenance	$250,000	3
	Ammonia	-	3
	Natural Gas: 2.2 MMbtu/hr @ $4.00/MMbtu	$77,088	7
	Pressure Drop	$226,000	3
	Catalyst Replacement (based on 3-yr catalyst life)	$2,100,000	5,6
	Catalyst Disposal	$0	
Total Direct Annual Costs		$2,653,088	
Indirect Annual Costs			
	Overhead	-	3
	Administrative, Tax & Insurance	$225,000	3
Total Indirect Annual Costs		$225,000	
TOTAL ANNUAL COST		$2,878,088	
Capital Recovery Factor		0.1315	2
Capital Recovery		$907,169	
TOTAL ANNUALIZED COSTS		$3,785,257	

SCONOx Incremental Cost (per gas turbine/HRSG)		Notes
SCONOx Annualized Costs	$3,785,257	
SCR Annualized Costs	$1,227,962	
Incremental Annualized Costs	$2,557,295	

Table 7C

Note No.	Notes: SCONOx Cost Effectiveness Analysis Source
1	Based on information from Duke/Fluor-Daniel.
2	From EPA/OAQPS Control Cost Manual. EPA-450/3-90-006. January 1990.
3	Based on 6/15/2000 telefax from Aalborg Industries to Duke/Fluor-Daniel. SCONOx capital cost is $36MM for four HRSGs.
4	Based on aqueous ammonia cost of $440/ton.
5	Based on information from May 8, 2000 "Testimony of J. Phyllis Fox, Ph.D. on Behalf of the California Unions for Reliable Energy on Air Quality Impacts of the Elk Hills Power Project", cost of replacement catalyst for SCONOx is 70% of initial capital investment. .
6	Based on information from May 5, 2000 letter from ABB Alstom Power to Bibb and Associates indicating that SCONOx catalyst life is guaranteed for a 3-year period.
7	Personal communication, ABB Environmental, 1/18/00

APPENDIX 6.2-7
EMISSION REDUCTION CREDIT CERTIFICATES PURCHASED FROM CHEVRON

AIR POLLUTION CONTROL DISTRICT
COUNTY OF SAN LUIS OBISPO

EMISSION REDUCTION CREDIT

CERTIFICATE NUMBER 681-Z1

ISSUED TO: LEGAL OWNER

Chevron Products Company
575 Lennon Lane Suite N2000
Walnut Creek, California 94598

Pursuant to Section 40709 of the California State Health and Safety Code and Rule 211 of the San Luis Obispo County Air Pollution Control District, it is hereby certified that the following emission credit is recorded in the name of the legal owner listed above.

This emission reduction occurred through the modification of Permit to Operate # 363-2, (application numbers 2353 and 2976) and by cancellation of Permits to Operate 344 and 358 for the shutdown of NOx emissions sources at the Estero Bay Marine Terminal, bank log number 2000-25.

POLLUTANT	CREDIT AMOUNT	QUARTERLY PROFILE			
		1st	2nd	3rd	4th
NOx	22.92 tons/yr	25%	25%	25%	25%

CONDITIONS:

1. Transfer of all or any portion of this Emission Reduction Credit (ERC) shall be in writing signed by the holder of the ERC in any form authorized by law. Transfer of title shall be complete upon filing such a deed or other instrument in the District's office and payment of the fee required by District Rule 306.

2. The use of banked Emission Reduction Credits to offset proposed increases is subject to the approval of the Air Pollution Control Officer and subject to all applicable rules and regulations in effect at the time of use.

3. Except as otherwise set forth above, the legal owner shall have exclusive rights to use and to authorize the use of the approved credits.

July 6, 2000
ISSUANCE DATE

Robert W. Carr

ROBERT W. CARR
AIR POLLUTION CONTROL OFFICER

H:\PERMITS\ERC\2353ERC.DOC

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AIR POLLUTION CONTROL DISTRICT
COUNTY OF SAN LUIS OBISPO

EMISSION REDUCTION CREDIT

CERTIFICATE NUMBER 680-Z1

ISSUED TO: LEGAL OWNER
Chevron Products Company
575 Lennon Lane Suite N2000
Walnut Creek, California 94598

Pursuant to Section 40709 of the California State Health and Safety Code and Rule 211 of the San Luis Obispo County Air Pollution Control District, it is hereby certified that the following emission credit is recorded in the name of the legal owner listed above.

This emission reduction occurred through the modification of Permit to Operate # 363-1, (application numbers 2854 and 2976) and by cancellation of Permits to Operate #344 and #358 for the shutdown of VOC emissions sources at the Estero Bay Marine Terminal, bank log number 2000-26.

POLLUTANT	CREDIT AMOUNT	QUARTERLY PROFILE			
		1st	2nd	3rd	4th
VOC	32.89 tons/yr	25%	25%	25%	25%

CONDITIONS:

1. Transfer of all or any portion of this Emission Reduction Credit (ERC) shall be in writing signed by the holder of the ERC in any form authorized by law. Transfer of title shall be complete upon filing such a deed or other instrument in the District's office and payment of the fee required by District Rule 306.

2. The use of banked Emission Reduction Credits to offset proposed increases is subject to the approval of the Air Pollution Control Officer and subject to all applicable rules and regulations in effect at the time of use.

3. Except as otherwise set forth above, the legal owner shall have exclusive rights to use and to authorize the use of the approved credits.

July 7, 2000
ISSUANCE DATE

Robert W. Carr
ROBERT W. CARR
AIR POLLUTION CONTROL OFFICER

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cleanair@sloapcd.dst.ca.us ✦ www.sloapcd.dst.ca.us

AIR POLLUTION
CONTROL DISTRICT
COUNTY OF SAN LUIS OBISPO

EMISSION REDUCTION CREDIT

CERTIFICATE NUMBER 685-Z1

ISSUED TO: Chevron Products Company
LEGAL OWNER 575 Lennon Lane Suite N2000
Walnut Creek, California 94598

Pursuant to Section 40709 of the California State Health and Safety Code and Rule 211 of the San Luis Obispo County Air Pollution Control District, it is hereby certified that the following emission credit is recorded in the name of the legal owner listed above.

This emission reduction occurred through the modification of Permit to Operate # 363-1, (application numbers 2857and 2976) and by cancellation of Permits to Operate #344 and #358 for the shutdown CO emissions sources at the Estero Bay Marine Terminal, bank log number 2000-29.

POLLUTANT	CREDIT AMOUNT	QUARTERLY PROFILE			
		1st	2nd	3rd	4th
CO	2.62 tons/yr	25%	25%	25%	25%

CONDITIONS:

1. Transfer of all or any portion of this Emission Reduction Credit (ERC) shall be in writing signed by the holder of the ERC in any form authorized by law. Transfer of title shall be complete upon filing such a deed or other instrument in the District's office and payment of the fee required by District Rule 306.

2. The use of banked Emission Reduction Credits to offset proposed increases is subject to the approval of the Air Pollution Control Officer and subject to all applicable rules and regulations in effect at the time of use.

3. Except as otherwise set forth above, the legal owner shall have exclusive rights to use and to authorize the use of the approved credits.

July 7, 2000
ISSUANCE DATE

Robert W. Carr

ROBERT W. CARR
AIR POLLUTION CONTROL OFFICER

H:\PERMITS\ERC\2857ERC.DOC

3433 Roberto Court • San Luis Obispo, CA 93401 • 805-781-5912 • FAX: 805-781-1002
cleanair@slcapcd.dst.ca.us • www.slocapcd.dst.ca.us

AIR POLLUTION CONTROL DISTRICT
COUNTY OF SAN LUIS OBISPO

EMISSION REDUCTION CREDIT

CERTIFICATE NUMBER 684-Z1

ISSUED TO: Chevron Products Company
LEGAL OWNER 575 Lennon Lane Suite N2000
Walnut Creek, California 94598

Pursuant to Section 40709 of the California State Health and Safety Code and Rule 211 of the San Luis Obispo County Air Pollution Control District, it is hereby certified that the following emission credit is recorded in the name of the legal owner listed above.

This emission reduction occurred through the modification of Permit to Operate # 363-1, (application numbers 2856 and 2976) and by cancellation of Permits to Operate #344 and #358 for the shutdown SOx emissions sources at the Estero Bay Marine Terminal, bank log number 2000-28.

POLLUTANT	CREDIT AMOUNT	QUARTERLY PROFILE			
		1st	2nd	3rd	4th
SOx	1.23 tons/yr	25%	25%	25%	25%

CONDITIONS:

1. Transfer of all or any portion of this Emission Reduction Credit (ERC) shall be in writing signed by the holder of the ERC in any form authorized by law. Transfer of title shall be complete upon filing such a deed or other instrument in the District's office and payment of the fee required by District Rule 306.

2. The use of banked Emission Reduction Credits to offset proposed increases is subject to the approval of the Air Pollution Control Officer and subject to all applicable rules and regulations in effect at the time of use.

3. Except as otherwise set forth above, the legal owner shall have exclusive rights to use and to authorize the use of the approved credits.

July 7, 2000
ISSUANCE DATE

Robert W. Carr

ROBERT W. CARR
AIR POLLUTION CONTROL OFFICER

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AIR POLLUTION
CONTROL DISTRICT
COUNTY OF SAN LUIS OBISPO

EMISSION REDUCTION CREDIT

CERTIFICATE NUMBER 682-Z1

ISSUED TO:
LEGAL OWNER

Chevron Products Company
575 Lennon Lane Suite N2000
Walnut Creek, California 94598

Pursuant to Section 40709 of the California State Health and Safety Code and Rule 211 of the San Luis Obispo County Air Pollution Control District, it is hereby certified that the following emission credit is recorded in the name of the legal owner listed above.

This emission reduction occurred through the modification of Permit to Operate # 363-1, (application numbers 2855 and 2976) and by cancellation of Permits to Operate #344 and #358 for the shutdown of PM10 emissions sources at the Estero Bay Marine Terminal, bank log number 2000-27.

POLLUTANT	CREDIT AMOUNT	QUARTERLY PROFILE			
		1st	2nd	3rd	4th
PM10	1.92 tons/yr	25%	25%	25%	25%

CONDITIONS:

1. Transfer of all or any portion of this Emission Reduction Credit (ERC) shall be in writing signed by the holder of the ERC in any form authorized by law. Transfer of title shall be complete upon filing such a deed or other instrument in the District's office and payment of the fee required by District Rule 306.

2. The use of banked Emission Reduction Credits to offset proposed increases is subject to the approval of the Air Pollution Control Officer and subject to all applicable rules and regulations in effect at the time of use.

3. Except as otherwise set forth above, the legal owner shall have exclusive rights to use and to authorize the use of the approved credits.

July 7, 2000
ISSUANCE DATE

Robert W. Carr

ROBERT W. CARR
AIR POLLUTION CONTROL OFFICER

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APPENDIX 6.2-8
CUMULATIVE IMPACTS ANALYSIS PROTOCOL

APPENDIX 6.2-8
CUMULATIVE IMPACTS ANALYSIS PROTOCOL

Potential cumulative air quality impacts that might be expected to occur resulting from the MBPP Project and other reasonably foreseeable projects are both regional and localized in nature. These cumulative impacts will be evaluated as follows.

Regional Impacts

Regional air quality impacts are possible for pollutants such as ozone, which involve photochemical processes that can take hours to occur. The MBPP Project will be required to provide emissions offsets (mitigation) for ozone precursors at a 1.0 to 1.0. Additional mitigation may be required by the CEC.

Although the relative importance of VOC and NOx emissions in ozone formation differs from region to region, and from day to day, most air pollution control plans in California require roughly equivalent controls (on a ton per year basis) for these two pollutants. The change in emissions of the sum of these pollutants, equally weighted, will be able to provide a rough estimate of the impact of the MBPP project on ozone levels. The net change in emissions of ozone precursors from the MBPP project will be compared with emissions from all sources within San Luis County, and within the South Central Coast Air Basin as a whole.

Air quality impacts of fine particulate, or PM_{10}, have the potential to be either regional or localized in nature. On a regional basis, an analysis similar to that presented above for ozone will be performed, looking at the three pollutants that can form PM_{10} in the atmosphere, VOC, SOx, and NOx, as well as at directly emitted particulate matter. SLOCAPCD regulations will require offsets to be provided for PM_{10} emissions from the project at a ratio of 1.0 to 1.0. Additional mitigation may be required by the CEC.

As in the case of ozone precursors, emissions of PM_{10} precursors are expected to have approximately equivalent ambient impacts in forming PM_{10}, per ton of emissions on a regional basis. A table will be provided that compares the net change in emissions of PM_{10} precursors from the MBPP project with emissions from all sources within San Luis Obispo County, and within the South Central Coast Air Basin as a whole.

Localized Impacts

Localized impacts from the MBPP project could result from emissions of carbon monoxide, oxides of nitrogen, sulfur oxides, and directly emitted PM_{10}. A dispersion modeling analysis of potential cumulative air quality impacts will be performed for all four of these pollutants.

In evaluating the potential cumulative localized impacts of the MBPP project in conjunction with the impacts of existing facilities and facilities not yet in operation but that are reasonably foreseeable, a potential impact area in which cumulative localized impacts could occur will first be identified. Based on the results of the air quality modeling analyses described above, "Significant" air quality impacts, as that term is defined in federal air quality modeling guidelines, will be determined. If the project's impacts do not exceed the significance levels, no cumulative impacts will be expected to occur, and no further analysis will be required. Otherwise, in order to ensure that other projects that might have significant cumulative impacts in conjunction with the MBPP project are identified, a search area with a radius of 20 km beyond the project's impact area will be used for the cumulative impacts analysis. For projects that have large emissions changes, a search area with a radius of 50 km around the project site will be used.

Within these search areas, three categories of projects with combustion sources will be used as criteria for identification:

- Projects that are existing and have been in operation since at least 1999.
- Projects for which air pollution permits to construct have been issued and that began operation after 1999.

- Projects for which air pollution permits to construct have not been issued, but that are reasonably foreseeable.

Projects that are existing and have been in operation since at least 1999 will be reflected in the ambient air quality data that is being used to represent background concentrations; consequently, no further analysis of the emissions from this category of facilities will be performed. The cumulative impacts analysis adds the modeled impacts of selected facilities to the maximum measured background air quality levels, thus ensuring that these existing projects are accounted for.

Projects for which air pollution permits to construct have been issued but that were not operational by 1999 will be identified through a request of permit records from SLOCAPCD. The search will be requested to be performed at two levels. For permits that are considered "major modifications" (i.e., emissions increases greater than 40 tons/year of NOx or SO_2, 15 tons/year of PM_{10}), a region within 50 km of the proposed project site will be evaluated. For projects that had smaller emissions changes, but still greater than 15 tons/year, a region within 20 km of the proposed project site will be evaluated. Projects that satisfy either of these criteria and that had a permit to construct issued after January 1, 1998, will be included in the cumulative air quality impacts analysis. The January 1, 1998 date was selected based on the typical length of time a permit to construct is valid and typical project construction times, to ensure that projects that are not reflected in the 1999 ambient air quality data are included in the analysis. Projects for which the emissions change was smaller than 15 tons/year will be assumed to be *de minimis*, and will not be included in the dispersion modeling analysis.

A list of projects within the area for which air pollution permits to construct have not yet been issued, but that are reasonably foreseeable, will also be requested from the SLOCAPCD staff.

Given the potentially wide geographic area over which the dispersion modeling analysis is to be performed, the ISCST3 model will be used to evaluate cumulative localized air quality impacts. The detailed modeling procedures, ISCST3 options, and meteorological data used in the cumulative impacts dispersion analysis will be the same as those used in the ambient air quality impacts analyses for the Project. The receptor grid will be spaced at 180 meters and will cover the area in which the detailed modeling analysis performed for the Project indicates the project will have impacts that exceed the PSD significance levels.

Cumulative Impacts Dispersion Modeling

The dispersion modeling analysis of cumulative localized air quality impacts for the proposed project will be evaluated in combination with other reasonably foreseeable projects and air quality levels attributable to existing emission sources, and the impacts will be compared to state or federal air quality standards for significant impact. As discussed above, the highest second-highest modeled concentrations will be used to demonstrate compliance with standards based on short-term averaging periods (24 hours or less).

Supporting information will be provided, including the following:

- Latest available emissions inventory for San Luis Obispo County and for the South Central Coast Air Basin;
- List of projects resulting from the screening analysis of permit files by the SLOCAPCD;
- Map showing locations of sources included in the cumulative air quality impacts dispersion modeling analysis;
- Stack parameters for sources included in the cumulative air quality impacts dispersion modeling analysis; and
- Output files for the dispersion modeling analysis.